BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-70:
2018 BART

Best Available Retrofit Technology (BART) Analysis of Control Options
For
Tri-State Generation & Transmission Association, Inc. – Craig Station Units 1 & 2

I. Source Description

Owner/Operator:	Tri-State Generation & Transmission Association, Inc.
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	10100222
Boiler Type:	Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired (Units 1 and 2)

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively.

Units 1 & 2: Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Fuel Gas Desulfurization (FGD) systems for the control of sulfur dioxide (SO_2) emissions. The boilers are equipped with ultra-low nitrogen oxide (NO_x) dual register burners with overfire air for minimization of NO_x emissions. The FGD and ultra low NO_x burner systems were required to be installed and fully operational by December 31, 2004 as a result of a consent decree with the Sierra Club (signed January 10, 2001).

Unit 3: Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of SO_2 and low-NO_x burners with overfire air.

All three units can use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for NO_x limits, effective January 1, 1997. Associated activities include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area. 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/PM_{10}., uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See "Craig APCD Technical Analysis" for further details. Not based on actual testing.

Only Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and in existence in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010, July 30, 2010, November 23, 2010, and December 8, 2010. The submittals are included as "Tri-State BART Submittals".

II. Source Emissions

Tri-State estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or "Baseline" Emissions", to be conservative, was the average of two previous (2004, 2005) of emissions data in the July 31, 2006 analysis. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses.

Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 2.

Table 2: Tri-State Craig Units 1 and 2 Baseline Emissions

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)
NO_x	5,190	0.278	5,372	0.271
SO_2	970	0.052	982	0.050
PM_{10}	80	0.006***	40	0.005***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO_2 emissions.
***The PM_{10} emission factor is determined from the most recent Title V permit compliance stack tests (January 2004).

III. Units Evaluated for Control

Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking sub-bituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. . Future nearby coal supplies could come from sources such as Trapper, ColoWyo, or Twentymile. Accordingly, the trend of future coal supplies is such that in the context of NO_x-forming characteristics, Craig 1&2 will continue to burn "bituminous-like" coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 1&2 in the future. Similar to PSCo, Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

Table 3: Craig Station Coal Specifications (2008)

Coal Mine/Region	ColoWyo	Trapper	Twentymile
Coal Rank Classification	Sub-bituminous, Class A	Sub-bituminous, Class A	Bituminous
H_2O (Moisture %)	17.42	16.7	9.62
Ash (%)	5.71	6.5	11.93
Sulfur (%)	0.37	0.44	0.52
Nitrogen (%)	1.35	~1.5	1.57
Heating Value (HHV Btu/lb)	10,392	9,800	11,084

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

Table 4: Uncontrolled emission factors for Craig BART-eligible sources[1]

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Unit 1	12	16.9	73.9	17.0
Unit 2	12	16.1	71.1	16.4

*SO_2 and PM/PM_{10} factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006 – 2008). Please refer to "Craig APCD Technical Analysis" for more details.

IV. BART Evaluation of Units 1 and 2

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

Wet FGD Upgrades – As discussed in EPA's BART Guidelines[2], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the wet FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Craig Units 1 and 2 if technically feasible. These upgrades include:
-Elimination of bypass reheat
-Installation of liquid distribution rings
-Installation of perforated trays
-Use of organic acid additives
-Improve or upgrade scrubber auxiliary equipment
-Redesign spray header or nozzle configuration

The current Operating Permit limits are depicted in Table 5.

Table 5: Craig Units 1 & 2 SO_2 Operating Permit Limits

	SO_2 limits (lb/MMBtu)			Reduction (%) Required
	3-hr rolling	30-day rolling	90-day rolling	90-day rolling
Units 1 & 2	1.2	0.160	0.130	90

The current Operating Permit also requires that 100% of the flue gas in the FGD be treated (Conditions 1.3.3 and 2.3.3) and that the Craig Unit 1 and 2 FGDs be designed to meet at least a 97.3% removal rate (Conditions 1.3.4 and 2.3.4).

[1] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

[2] EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO_2 from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney. Colorado Ute Electric Association, which owned Craig before Tri-State, installed wet limestone FGD systems, on Craig Units 1 and 2 when the units began operations in 1980 and 1979, respectively. Tri-State upgraded these FGD systems in the 2003 – 2004 timeframe. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu.

At the Division's request, Tri-State submitted a SO_2 upgrade analysis to the Division on June 4, 2010 regarding potential upgrades for the wet FGD systems at Craig Station Units 1 and 2.

Tri-State examined potential upgrades to the Craig wet FGD systems, with the following results:

-*Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations. After the Yampa Environmental Project (YEP) Upgrades (2003 – 2004), 100 percent of the flue gas now passes through the scrubber with no reheat and no bypassing.

-*Installation of liquid distribution rings:* Liquid distribution rings were not installed during the YEP; however, Tri-State determined that installation of perforated trays, described below, accomplished the same objective.

-*Installation of perforated trays:* Upgrades during the YEP included installation of a perforated plate tray in each scrubber module. The trays improve the absorption of SO_2 by increasing the contact between the flue gas and the limestone slurry. The trays also function like Slurry Distribution Rings by redirecting slurry from running down the absorber wall back to the flue gas flow stream.

-*Use of organic acid additives:* Organic acid additives such as Dibasic Acid (DBA) can be used to improve SO_2 removal efficiency by increasing scrubbing liquor alkalinity. This option was considered for Craig Units 1 and 2 during YEP; however, it was not selected for the following reasons:

1. DBA has not been tested at the very low inlet SO_2 concentrations seen at Craig Units 1 and 2.

2. DBA could cause changes in sulfite oxidation with impacts on SO_2 removal and solids settling and dewatering characteristics.

3. Installation of the perforated plate tray accomplished the same objective of increased SO_2 removal.

-*Improve or upgrade scrubber auxiliary equipment:* YEP included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:

1. Two vertical ball mills were installed for additional limestone processing capability for increased SO_2 removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high SO_2 removal rates.

2. Forced oxidation within the SO_2 removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.

3. A ventilation system was installed for each reaction tank.

4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.

5. Tri-State installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.

6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased SO_2 removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.

7. Instrumentation and controls were modified to support all of the new equipment.

-*Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during YEP. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, Tri-State and the Division concur that there are not any technically feasible upgrade options for Craig Station Units 1 and 2. However, the Division has evaluated the option of tightening the SO_2 emission limit for Craig Units 1 and 2.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The control effectiveness of tightening the 30-day rolling emission limits on Craig Units 1 and 2 have been evaluated by the Division. The Division analyzed the baseline period (2006 – 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 6, to determine potential control effectiveness, if any. This information allows the Division to set a more relevant emission limit for Craig Units 1 and 2 using representative actual emissions.

Table 6: Craig Units 1 & 2 30-day rolling emission rates (baseline 2006 - 2008)

Unit	Maximum 30-day rolling emission rate (lb/MMBtu)	Average 30-day rolling emission rate (lb/MMBtu)
Craig Unit 1	0.081	0.052
Craig Unit 2	0.093	0.079

Step 4: Evaluate Impacts and Document Results

Since there are not any remaining control technologies available for Craig Station Units 1 and 2, there are not any impacts to evaluate or results to document.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with emission limit tightening. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 7 shows the number of days pre- and post-control. Table 8 depicts the visibility results (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 protocol[3], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM_{10}) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions at 0.10 lb/MMBtu (wet FGD).

[3] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 7: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour	1	0.166	Mt. Zirkel Wilderness	207	---	---	123	---	---
	2	0.161							
Wet FGD	1	0.150		207	206	1	123	123	0
	2	0.150		207	207	0	123	123	0
Wet FGD	1	0.120		207	204	3	123	123	0
	2	0.120		207	204	3	123	123	0
Wet FGD	1	0.110*		n/a					
	2	0.110*		n/a					
Wet FGD	1	0.100		207	203	4	123	123	0
	2	0.100		207	203	4	123	123	0
Wet FGD	1	0.070		207	202	5	123	122	1
	2	0.070		207	203	4	123	122	1
Combo	1	0.100		207	57	150	123	12	111
	2	0.100							

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Craig BART Modeling Summary" for more details.

Table 8: Visibility Results – SO_2 Control Options

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Output (@ 98th Percentile Impact)*	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour	1	0.166	3.73	---	---
	2	0.161			
Wet FGD	1	0.150	3.72	0.01	0%
	2	0.150	3.72	0.01	0%
Wet FGD	1	0.120	3.70	0.02	1%
	2	0.120	3.71	0.02	1%
Wet FGD	1	0.110*	3.70	0.03	1%
	2	0.110*	3.70	0.03	1%
Wet FGD	1	0.100	3.69	0.03	1%
	2	0.100	3.70	0.03	1%
Wet FGD	1	0.070	3.68	0.05	1%
	2	0.070	3.68	0.05	1%
Combo	1	0.070	1.17	2.56	69%
	2	0.070			

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Craig BART Modeling Summary" for more details.

Step 6: Select BART Control

There are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 and determined that a more stringent 30-day rolling SO_2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology. The tighter emission limits are achievable without additional capital investment. An SO_2 limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

B. Filterable Particulate Matter (PM_{10})

Craig Units 1 and 2 are each equipped with pulse jet fabric filter (PJFF) baghouses to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 9 shows the most recent stack test data (2004). Real-time data demonstrates that these baghouses are meeting >95% control. The Title V permit limit is 0.03 lb/MMBtu (Condition 1.1.3). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 9: Craig Units 1 and 2 Stack Test Results (2004)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM_{10}	0.006	0.005
PM_{10} Control efficiency	99.23%	99.35%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations. Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado's SIP for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements (4/19/01), as approved by EPA at 66 FR 35374 (07/05/01).

The Division has determined that the existing Unit 1 and 2 pulse jet fabric filter baghouses and the emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM_{10}.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies
Tri-State identified five options for NO_x control:
New/modified Low NO_x Burners (LNBs) with 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

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 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.

Tri-State contacted Motobec, the manufacturer of ROFA® technology, to determine if ROFA is feasible for Craig Units 1 and 2. Mobotec could not give Tri-State a definitive guarantee for reductions due to the variability in the quality of coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[4]. While ROFA is considered superior to OFA/SOFA alone, ROFA alone is not superior to LNB+OFA and is not expected to increase emissions reductions for Craig Units 1 and 2. The Division asserts that ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for these units, ROFA® technology is not considered further in this analysis.

Neural network system combustion controls: Tri-State received a neural network proposal from NeuCo in April 2006. The proposal offers to enhance the existing Craig 1&2 control system by providing combustion optimization technology. For a given set of objectives, a neural network directs the unit's distributive control system (DCS) or other control systems to optimize the boiler performance.

Based on review of the Craig 1&2 current operations, NeuCo stated that Craig 1&2 appear to be good candidates for the optimization system. Key aspects to neural network success are the training support provided by the supplier, as well as achieving buy-in from plant operators. Tri-State states that it is important to note that the condition of the unit(s) and the manner in which the unit(s) is operated prior to the installation of the combustion optimization system also play an important role in determining potential NO_x reductions. Neural network system combustion controls appear to be technically feasible for Craig Units 1 and 2.

[4] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

SNCR: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. This 20-40% range includes units operating with LNB/combustion modifications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Craig Units 1 and 2. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

While a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for Craig, two retrofit SCR systems, the 0.07 lb/MMBtu controlled NO_x value is more expected, although Tri-State asserts that the units cannot achieve below 0.08 lb/MMBtu. See "Tri-State BART Submittals" for more details. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. SCR is a technically feasible alternative for Craig Units 1 and 2.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[5] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[6] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

[5] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[6] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

LNB/SOFA/LNB+SOFA: Craig Units 1 and 2 are already equipped with ultra-low NO_x burners with over-fire air (ULNB+OFA) as part of a consent decree. Requirements for these control systems were adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements," dated April 19, 2001. Table 1 illustrates that these systems achieve 39.7% and 41.1% NO_x reductions (based on actual emissions) on Units 1 and 2, respectively.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[7]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[8] 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Craig Units 1 and 2 to determine control efficiencies and annual reductions.

LNBs with OFA Upgrades: Tri-State noted in the original BART submittal (July 31, 2006) that ACT proposed that a modified LNB with upgraded OFA system could achieve 10 – 15% NO_x reduction above current levels. Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. These control refinements consist mostly of more precise control of fuel and air for combustion. This study conducted by Black & Veatch (B&V) notes that these refinements could achieve approximately 0- 2 % control. B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that the Craig units already have ultra-low NO_x burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinements from December 8, 2010.

Neural network system combustion controls: Tri-State noted in the original BART submittal (July 31, 2006) that NeuCo provided a neural network proposal projecting that an optimization system could achieve 5 – 15% NO_x reductions. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. This study, conducted by Black & Veatch (B&V), notes that the NN equipment will be minimal, consisting of a few computer servers that will interface with existing systems in the same location(s). NN system combustion controls could achieve approximately 0 – 5% control.

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[7] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf

[8] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study control efficiency for NN system controls submitted on December 8, 2010.

SNCR: Tri-State stated in the May 14, 2010 submittal that based on the boiler configuration, Tri-State could expect a continuous NO_x reduction performance with SNCR technology in the range of 10 – 15%. This is based on Tri-State's extensive research into the application of SNCR technology at Craig Station. The vast majority of the research was focused on system performance and impacts on plant performance. Tri-State staff conducted a visit to First Energy's Eastlake and Sammis power plants in Ohio; this visit was specifically design to evaluate boiler designs due to the similarity in boiler/burner configurations similar to the Craig Station boilers. These estimates are lower than EPA's SNCR Air Pollution Control Technology Fact Sheet, which estimates SNCR between 30 – 50% control. Other Colorado facilities estimated SNCR as achieving between 17 – 40% NO_x control. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010. The results of this study varied significantly depending on what coal type was utilized and were applicable for Craig Unit 1. Control effectiveness has been historically noted to be lower for wall fired boilers similar to the Craig boilers; therefore the Divisions considers approximately 15% to be a reasonable control effectiveness for SNCR.

SCR: Tri-State stated in the May 14, 2010 submittal the expected emission rates for Craig Units 1 and 2 when applying SCR are 0.08 lb/MMBtu. Tri-State did not specify if this estimate was a 30-day rolling averages, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu[9]or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve NO_x reduction efficiencies greater than 85% with emission rates between 0.04 and 0.07 lb/MMBtu (during the ozone season).[10] EPA's AP-42 emission factor tables estimate SCR as achieving 75 – 85% NO_x emission reductions. However, an appropriate margin of error must be applied when evaluating SCR. The design goal emission rate may be lower than the permitted limit to ensure that unnecessary non-compliance periods do not become an issue. Table 10 depicts a comparison of SCR control efficiencies. The Division adjusted Tri-State's estimate to 0.07 lb/MMBtu based on the reasoning above.

[9] Public Service Company of Colorado (April 20, 2010), Colorado Energy Nations Company (November 12, 2009), Colorado Springs Utilities (February 20, 2009), and Platte River Power Authority (January 22, 2009) all note that their individual EGUs can achieve 0.070 lb/MMBtu or even lower on a 30-day rolling average basis.

[10] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Table 10: SCR Control Efficiency Comparison

Unit	Baseline (lb/MMBtu)	Control Efficiency (%)		Resultant Emissions (lb/MMBtu)	
		Tri-State Estimate	Division Estimate	Tri-State Estimate (annual average)	Division Estimate (annual average)
Craig Unit 1	0.278	71.4	74.9	0.080	0.070
Craig Unit 2	0.271	70.5	74.0	0.080	0.070

Table 11 summarizes each available technology and technical feasibility for NO_x control.

Table 11: Craig Units 1 and 2 NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners/Ultra-low NO_x burners (LNB/ULNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed
Air Staging – overfire 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 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

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 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.[11] Tri-State estimates that the initial cost of combustion control refinement at about $2,200,000 with an annualized 20-year cost of $122,000. The Division notes that the Craig units already have ultra-low NO_x burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinement cost estimates from December 8, 2010.

[11] Bryk and Kleisley, 2000. "First Commercial Application of DRB-4Z™ Ultra-Low NOx Coal-Fired Burner." Presented to POWER-GEN International 2000. November 14-16, 2000. Orlando, Florida.

Neural network system: Tri-State did not provide a quantitative evaluation of the application of a neural network system to the Division. There are three other facilities in Colorado alone using neural network systems from the same provider that Tri-State contacted.[12] It is unknown why Tri-State will provide further analysis of this system. Costs for these systems are very specific to individual units, so the Division cannot estimate costs for this option. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. Tri-State estimates that the initial cost of neural network systems (per unit) at about $800,000 with an annualized 20-year cost of $280,000. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study cost estimates for NN system controls submitted on December 8, 2010.

SNCR: A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.[13] The Tri-State-estimated SNCR costs for operating expenses are 67% for Craig Units 1 and 2 (individually). Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[14]

The cost effectiveness for SNCR on Units 1 and 2 (at 15% control efficiency) is approximately $4,877 and $4,712 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (similar to Units 1 and 2) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing $590 - $1,100 per ton of NO_x reduced, depending on initial capital costs and capacity factor. [15,16] It should be noted that Tri-State is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers, therefore costs will be higher. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[17] On a linear scale, based on the NESCAUM estimates and assuming an achieved rate of 0.23 lb/MMBtu, the costs should be approximately $2,500 per ton. Tri-State and the Division's revised estimates are above this range; the Division has inquired about the reagent and auxiliary power costs, but has not received feedback from Tri-State. The costs for these two items are higher than other Colorado facility estimates.

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[12] NeuCo White Papers and Case Studies. http://www.neuco.net/library/case-studies/default.cfm and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NOx Emission Control Cost and Technical Feasibility Information."

[13] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

[14] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[15] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[16] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[17] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division accepts Tri-State's capital and operation/maintenance costs for this analysis.

SCR: Recent NESCAUM studies estimate SCR retrofits on wall fired boilers achieving NO_x emission rates of 0.15 – 0.25 lb/MMBtu and emission reductions of 75 – 85% as costing $1,700 - $3,200 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[18,19 20,21] It should be noted that Tri-State is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. Tri-State's estimates are above this range; on a linear scale (achieving 0.07 lb/MMBtu); the costs should be approximately $7,000 per ton. The Division's revised cost estimates are close to this estimate; therefore, the Division concludes that these cost estimates are reasonable.

Table 12, Table 13, Table 14, and Table 15 depict controlled NO_x emissions and control cost comparisons.

Table 12: Craig Unit 1 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	5,190	0.278	
Combustion control refinements	2	5,087	0.273	0.31
Neural network system	5	4,931	0.264	0.30
SNCR	15	4,412	0.236	0.27
SCR	78.0	1,142	0.061	0.070

[18] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[19] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[20] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[21] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

Table 13: Craig Unit 2 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	5,372	0.271	
Combustion control refinements	2	5,264	0.265	0.31
Neural network system	5		0.257	0.30
SNCR	15	4,566	0.230	0.27
SCR	74	1,397	0.070	0.081

Table 14: Craig Unit 1 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Combustion control refinements	104	$122,000	$1,175	$1,175
Neural network system	260	$280,000	$1,079	$1,015
SNCR	779	$3,797,000	$4,877	$6,776
SCR	4,048	$25,036,709	$6,184	$6,394

Table 15: Craig Unit 2 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Combustion control refinements	107	$122,000	$1,136	$1,136
Neural network system	269	$280,000	$1,043	$980
SNCR	806	$3,797,000	$4,712	$4,712
SCR	3,975	$25,036,709	$6,298	$6,702

Energy and Non-Air Quality Impacts

LNB Upgrades/Neural network system(s): There are no known non-air quality impacts associated with upgrades on low-NO_x burner systems or neural network systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

SNCR/ SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas.

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 16 shows the number of days pre- and post-control. Table 17 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[22], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels.

[22] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions at 0.10 lb/MMBtu (wet FGD control).

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 16: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour	1	0.352	Mt. Zirkel Wilderness	207	---	---	123	---	---
	2	0.345							
SNCR	1	0.236		207	192	15	123	123	0
	2	0.230		207	194	13	123	123	0
SCR	1	0.07		207	165	42	123	123	0
	2	0.07		207	166	41	123	123	0
Combo	1	0.07		207	57	150	123	12	111
	2	0.07							

Table 17: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hour	1	0.352	3.73	---	---	---
	2	0.345				
SNCR	1	0.236	3.42	0.31	8%	$12,327,922
	2	0.230	3.42	0.31	8%	$12,327,922
SCR	1	0.07	2.72	1.01	27%	$24,887,384
	2	0.08	2.79	0.94	25%	$26,691,207
Combo	1	0.07	1.17	2.56	69%	$19,537,034
	2	0.07				

Step 6: Select BART Control

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

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

Craig Unit 1: 0.070 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.080 lb/MMBtu (30-day rolling average)

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

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

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

This BART determination is consistent with the information provided by the FLMs and is supported by the associated visibility improvement information as well as the SCR cost information provided in the SIP materials and otherwise reflected in the 2014 hearing record.

In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a BART reassessment for Craig Unit 1. This reassessment evaluates the additional scenarios:

Scenario 1 (Close by December 31, 2025): Table 18 below assumes an amortization period of four years and four months of operation from the projected compliance date to the date of retirement (December 31, 2025) and that control technology could be installed by August 31, 2021, consistent with the 2014 BART determination In Table 19 below, an assumed amortization period of eight years of operation[23] is used since a projected compliance date could occur earlier depending on the alternative selected. Both of these assumed amortization periods change the remaining useful life for the alternatives as Craig Unit 1 will no longer remain in service for the 20-year amortization period used in the 2014 BART determination, depending on the alternative selected[24]. Both of these reduced timeframes change the cost effectiveness for the alternatives as follows:

Table 18: Craig Unit 1 NOx Cost Comparisons (4 years, 4 months of operation)

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$6,172,522	$7,928
SCR	4,048	$64,106,699	$15,835

Table 19: Craig Unit 1 NOx Cost Comparisons (8 years of operation)

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)
Baseline	0	$0	$0
SNCR	779	$4,755,842	$6,109
SCR	4,048	$41,476,535	$10,245

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

Scenario 2: A cease coal burning date of August 31, 2021 with the option to convert the unit to natural-gas firing by August 31, 2023. In the case of a conversion to natural-gas firing, a 30-day rolling average NOx emission limit of no more than 0.07 lb/MMBtu applies after August 31,

[23] Operation period begins calendar year 2018 (December 31, 2017).

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

2021. This scenario (without the inclusions below) is equivalent to the 2014 BART determination.

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

The scenario options under this BART reassessment are the result of an agreement. This reassessment relies on the 2014 BART determination for Craig Unit 1 and supplements that determination to reflect the terms of the agreement. This agreement achieves greater air quality benefits than the 2011 Regional Haze SIP. Both of these scenarios achieve greater NOx reductions and other environmental co-benefits compared to the 2014 BART determination.

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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-71:
BART CALPUFF

BART CALPUFF
Class I Federal Area
Individual Source Attribution
Visibility Impairment Modeling Analysis
for
Tri-State Generation & Transmission Association
Craig Station Units 1 and 2
(Revised)

March 3, 2006

Colorado Department of Public Health & Environment
Air Pollution Control Division
4300 Cherry Creek Drive South
Denver, Colorado 80246

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1. Executive Summary

Federal law requires Best Available Retrofit Technology (BART) for any BART-eligible source that ‘‘emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility” in any mandatory Class I federal area. Pursuant to federal regulations, states have the option of exempting a BART-eligible source from the BART requirements based on dispersion modeling demonstrating that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area.

The Division has proposed state regulations establishing criteria and procedures for determining which Colorado sources will be subject to the BART requirement. The Division’s proposal is scheduled for a March 16, 2006 hearing before the Air Quality Control Commission. In advance of the hearing, and in preparation for the submittal of a state implementation plan for regional haze, the Division has performed air quality modeling with the CALPUFF modeling system to assess which BART-eligible sources in Colorado are likely to be subject to BART based on the proposed state regulation.

According to 40 CFR Part 51, Appendix Y (BART guideline), a BART-eligible source is considered to “contribute” to visibility impairment in a Class I area if the modeled 98th percentile change in deciviews is equal to or greater than the “contribution threshold.” Any BART-eligible source determined to cause or contribute to visibility impairment in any Class I area is subject to BART. In this report, the Division used a “contribution threshold” of 0.5 deciviews, as prescribed by the regulatory proposal pending before the Commission.

The Division has applied the CALPUFF modeling system with three years of meteorological data to determine if the 98th percentile 24-hour change in visibility (delta-deciview) from a BART-eligible source is equal to or greater than a contribution threshold of 0.5 deciviews at any Class I area. This initial phase of the BART modeling process is referred to as the “subject-to-BART” analysis. The modeling includes SO_2, NOx, and direct PM10 emissions from all BART-eligible units at a given facility.

While the modeling results in this report may be used to support regulatory decision making, additional modeling performed by the Division or source operator may supersede the results. If additional modeling is performed, it should be consistent with recommendations in the Division’s modeling protocol. Subsequent modeling performed by the source operator will be subject to Division review and approval. Moreover, the contribution threshold and other criteria used for this modeling demonstration have not been finalized and may change in the final rule adopted by the Commission. Therefore, the results in this report are not a final agency action. Any source that the Division determines is subject to BART will receive a separate notice of the agency’s final determination. Such separate notice will occur after the Commission acts on the proposed regulations establishing criteria and procedures for determining which sources will be subject to the BART requirement.

The maximum 98th percentile delta-deciview value from Craig Station Units 1 and 2 at any Class I federal area is 2.689 deciviews, assuming natural background conditions and monthly

f(RH) values. The impact is above the contribution threshold of 0.5 deciviews. The maximum impact occurs at the Mount Zirkel Wilderness Area. For the three-year period modeled, there are 496 days with an estimated impact over the contribution threshold of 0.5 deciviews.

2. Introduction

Federal law requires Best Available Retrofit Technology (BART) for any BART-eligible source that ‘‘emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility” in any mandatory Class I federal area. Pursuant to federal regulations, states have the option of exempting a BART-eligible source from the BART requirements based on dispersion modeling demonstrating that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area.

Federal regulations implementing the BART requirement afford states some latitude in the criteria in determining whether a BART-eligible source is subject to BART. The Division has proposed state regulations establishing criteria and procedures for determining which Colorado sources will be subject to the BART requirement. The Division’s proposal is scheduled for a March 16, 2006 hearing before the Air Quality Control Commission. In advance of the hearing, and in preparation for the submittal of a state implementation plan for regional haze, the Division has performed air quality modeling with the CALPUFF modeling system to assess which BART-eligible sources in Colorado are likely to be subject to BART based on the proposed state regulation.

According to 40 CFR Part 51, Appendix Y (BART guideline), a BART-eligible source is considered to “contribute” to visibility impairment in a Class I area if the modeled 98th percentile change in deciviews is equal to or greater than the “contribution threshold.” Any BART-eligible source determined to cause or contribute to visibility impairment in any Class I area is subject to BART. The Division has proposed a state regulation establishing a “contribution threshold” of 0.5 deciviews. In this report, the assumed “contribution threshold” is 0.5 deciviews.

The Division has applied the CALPUFF modeling system with three years of meteorological data to determine if the 98th percentile 24-hour change in visibility (delta-deciview) from a BART-eligible source is equal to or greater than a contribution threshold of 0.5 deciviews at any Class I area. This initial phase of the BART modeling process is referred to as the “subject-to-BART” analysis. The modeling includes SO_2, NOx, and direct PM10 emissions from all BART-eligible units at a given facility.

While the modeling results in this report may be used to support regulatory decision making, additional modeling performed by the Division or source operator may supersede the results. If additional modeling is performed, it should be consistent with recommendations in the Division’s modeling protocol. Any subsequent modeling performed by the source operator will be subject to Division review and approval. Moreover, the contribution threshold and other criteria used for this modeling demonstration have not been finalized and may change in the final rule adopted by the Commission. Therefore, the results in this report are not a final agency action. Any source that the Division determines is subject to BART will receive a separate notice of the agency’s final determination. Such separate notice will occur after the Commission acts on the proposed regulations establishing criteria and procedures for determining which sources will be subject to the BART requirement.

Relevant language from the BART guideline is included, below, to show the modeling recommendations in context. Other sections of this report explain how the Division implemented the recommendations. The BART guidelines set out 40 CFR Part 51, Appendix Y, provide in part:

> ***III. HOW TO IDENTIFY SOURCES "SUBJECT TO BART"***
> *Once you have compiled your list of BART-eligible sources, you need to determine whether (1) to make BART determinations for all of them or (2) to consider exempting some of them from BART because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. If you decide to make BART determinations for all the BART-eligible sources on your list, you should work with your regional planning organization (RPO) to show that, collectively, they cause or contribute to visibility impairment in at least one Class I area. You should then make individual BART determinations by applying the five statutory factors discussed in Section IV below.*
>
> *On the other hand, you also may choose to perform an initial examination to determine whether a particular BART-eligible source or group of sources causes or contributes to visibility impairment in nearby Class I areas. If your analysis, or information submitted by the source, shows that an individual source or group of sources (or certain pollutants from those sources) is not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area, then you do not need to make BART determinations for that source or group of sources (or for certain pollutants from those sources). In such a case, the source is not "subject to BART" and you do not need to apply the five statutory factors to make a BART determination. This section of the Guideline discusses several approaches that you can use to exempt sources from the BART determination process.*
>
> ***A. What Steps Do I Follow to Determine Whether A Source or Group of Sources Cause or Contribute to Visibility Impairment for Purposes of BART?***
> ***1. How Do I Establish a Threshold?***
> *One of the first steps in determining whether sources cause or contribute to visibility impairment for purposes of BART is to establish a threshold (measured in deciviews) against which to measure the visibility impact of one or more sources. A single source that is responsible for a 1.0 deciview change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 deciview change may still contribute to visibility impairment and thus be subject to BART.*
>
> *Because of varying circumstances affecting different Class I areas, the appropriate threshold for determining whether a source "contributes to any visibility impairment" for the purposes of BART may reasonably differ across States. As a general matter, any threshold that you use for determining whether a source "contributes" to visibility impairment should not be higher than 0.5 deciviews.*
>
> *In setting a threshold for "contribution," you should consider the number of emissions sources affecting the Class I areas at issue and the magnitude of the individual sources'*

impacts.[5] *In general, a larger number of sources causing impacts in a Class I area may warrant a lower contribution threshold. States remain free to use a threshold lower than 0.5 deciviews if they conclude that the location of a large number of BART eligible sources within the State and in proximity to a Class I area justify this approach.*[6]

2. What Pollutants Do I Need to Consider?

You must look at SO2, NOx, and direct particulate matter (PM) emissions in determining whether sources cause or contribute to visibility impairment, including both PM10 and PM2.5. Consistent with the approach for identifying your BART-eligible sources, you do not need to consider less than de minimis emissions of these pollutants from a source.

As explained in section II, you must use your best judgement to determine whether VOC or ammonia emissions are likely to have an impact on visibility in an area. In addition, although as explained in Section II, you may use PM10 an indicator for particulate matter in determining whether a source is BART eligible, in determining whether a source contributes to visibility impairment, you should distinguish between the fine and coarse particle components of direct particulate emissions. Although both fine and coarse particulate matter contribute to visibility impairment, the long-range transport of fine particles is of particular concern in the formation of regional haze. Air quality modeling results used in the BART determination will provide a more accurate prediction of a source's impact on visibility if the inputs into the model account for the relative particle size of any directly emitted particulate matter (i.e. PM_{10} vs. $PM_{2.5}$).

3. What Kind of Modeling Should I Use to Determine Which Sources and Pollutants Need Not Be Subject to BART?

This section presents several options for determining that certain sources need not be subject to BART. These options rely on different modeling and/or emissions analysis approaches. They are provided for your guidance. You may also use other reasonable approaches for analyzing the visibility impacts of an individual source or group of sources.

Option 1: Individual Source Attribution Approach (Dispersion Modeling)

You can use dispersion modeling to determine that an individual source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area and thus is not subject to BART. Under this option, you can analyze an individual source's impact on visibility as a result of its emissions of SO_2, NO_x and direct PM emissions. Dispersion modeling cannot currently be used to estimate the predicted impacts on visibility from an individual source's emissions of VOC or ammonia. You may use a more qualitative

[5] *We expect that regional planning organizations will have modeling information that identifies sources affecting visibility in individual class I areas.*

[6] *Note that the contribution threshold should be used to determine whether an individual source is reasonably anticipated to contribute to visibility impairment. You should not aggregate the visibility effects of multiple sources and compare their collective effects against your contribution threshold because this would inappropriately create a "contribute to contribution" test.*

assessment to determine on a case-by-case basis which sources of VOC or ammonia emissions may be likely to impair visibility and should therefore be subject to BART review, as explained in section II.A.3. above.

You can use CALPUFF[7] or other appropriate model to predict the visibility impacts from a single source at a Class I area. CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment and is currently the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long range transport of primary pollutants.[8] It can also be used for some other purposes, such as the visibility assessments addressed in today's rule, to account for the chemical transformation of SO_2 and NO_x.

There are several steps for making an individual source attribution using a dispersion model:

1. Develop a modeling protocol.

Some critical items to include in the protocol are the meteorological and terrain data that will be used, as well as the source-specific information (stack height, temperature, exit velocity, elevation, and emission rates of applicable pollutants) and receptor data from appropriate Class I areas. We recommend following EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts[9] for parameter settings and meteorological data inputs. You may use other settings from those in IWAQM, but you should identify these settings and explain your selection of these settings.

One important element of the protocol is in establishing the receptors that will be used in the model. The receptors that you use should be located in the nearest Class I area with sufficient density to identify the likely visibility effects of the source. For other Class I areas in relatively close proximity to a BART-eligible source, you may model a few strategic receptors to determine whether effects at those areas may be greater than at the nearest Class I area. For example, you might chose to locate receptors at these areas at the closest point to the source, at the highest and lowest elevation in the Class I area, at the IMPROVE monitor, and at the approximate expected plume release height. If the highest modeled effects are observed at the nearest Class I area, you may choose not to analyze the other Class I areas any further as additional analyses might be unwarranted.

---

[7] *The model code and its documentation are available at no cost for download from http://www.epa.gov/scram001/tt22.htm#calpuff .*

[8] *The Guideline on Air Quality Models, 40 CFR part 51, appendix W, addresses the regulatory application of air quality models for assessing criteria pollutants under the CAA, and describes further the procedures for using the CALPUFF model, as well as for obtaining approval for the use of other, nonguideline models.*

[9] *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts,* U.S. Environmental Protection Agency, EPA-454/R-98-019, December 1998.

You should bear in mind that some receptors within the relevant Class I area may be less than 50 km from the source while other receptors within that same Class I area may be greater than 50 km from the same source. As indicated by the Guideline on Air Quality Models, 40 CFR part 51, appendix W, this situation may call for the use of two different modeling approaches for the same Class I area and source, depending upon the State's chosen method for modeling sources less than 50 km. In situations where you are assessing visibility impacts for source-receptor distances less than 50 km, you should use expert modeling judgment in determining visibility impacts, giving consideration to both CALPUFF and other appropriate methods.

In developing your modeling protocol, you may want to consult with EPA and your regional planning organization (RPO). Up-front consultation will ensure that key technical issues are addressed before you conduct your modeling.

2. [Run model in accordance] with the accepted protocol and compare the predicted visibility impacts with your threshold for "contribution."

You should calculate daily visibility values for each receptor as the change in deciviews compared against natural visibility conditions. You can use EPA's "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule," EPA-454/B-03-005 (September 2003) in making this calculation. To determine whether a source may reasonably be anticipated to cause or contribute to visibility impairment at Class I area, you then compare the impacts predicted by the model against the threshold that you have selected.

The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used, as such emission rates could produce higher than normal effects than would be typical of most facilities. We recommend that States use the 24 hour average actual emission rate from the highest emitting day of the meteorological period modeled, unless this rate reflects periods start-up, shutdown, or malfunction. In addition, the monthly average relative humidity is used, rather than the daily average humidity – an approach that effectively lowers the peak values in daily model averages.

For these reasons, if you use the modeling approach we recommend, you should compare your "contribution" threshold against the 98th percentile of values. If the 98th percentile value from your modeling is less than your contribution threshold, then you may conclude that the source does not contribute to visibility impairment and is not subject to BART.

2.1. Modeling Process Overview

For each BART-eligible source that emits SO_2, NOx, and/or direct PM10, the constant emission rates shown in section 4 are used in the CALPUFF modeling system to estimate the daily change in visibility compared against natural background conditions (delta-deciview) at each Class I federal area in the modeling domain. The 98th percentile delta-deciview value at each Class I area is compared to the "contribution threshold" to determine if the source contributes to visibility impairment.

The CALPUFF[1] modeling system consists of CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields of variables such as wind and temperature. CALPUFF simulates the transport, dispersion, and transformation of pollutants emitted from the source and calculates hourly concentration and/or deposition flux values at each receptor in the modeling domain. CALPOST calculates time-averaged concentration and deposition flux values from the CALPUFF predictions and performs visibility calculations like those described in the section 2.2.

2.2. Visibility Calculations

The general theory for performing visibility calculations with the CALPUFF modeling system is described in several federal documents, including:

- "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts" (IWAQM, 1998)
- "Federal Land Manager's Air Quality Related Values Workgroup (FLAG): Phase I Report" (FLAG, 2000)
- "A User's Guide for the CALPUFF Dispersion Model" (Scire, 2000)

In general, visibility is characterized either by visual range (the greatest distance that a large object can be seen) or by the light extinction coefficient, which is a measure of the light attenuation per unit distance due to scattering and absorption by gases and particles.

Visibility is impaired when light is scattered in and out of the line of sight and by light absorbed along the line of sight. The light extinction coefficient (b_{ext}) considers light extinction by scattering (b_{scat}) and light extinction by absorption (b_{abs}):

$$b_{ext} = b_{scat} + b_{abs}$$

The scattering components of extinction can be represented by these components:

- light scattering due to air molecules = Rayleigh scattering = $b_{rayleigh}$
- light scattering due to particles = b_{sp}

The absorption components of extinction can be represented by these components:

- light absorption due to gaseous absorption = b_{ag}

[1] CALPUFF is a non-steady-state Lagrangian puff model.

- light absorption due to particle absorption = b_{ap}

Particle scattering, b_{sp}, can be expressed by its components:

$$b_{sp} = b_{SO4} + b_{NO3} + b_{OC} + b_{SOIL} + b_{Coarse}$$

where:

- b_{SO4} = scattering coefficient due to sulfates = $3[(NH_4)_2SO_4]f(RH)$
- b_{NO3} = scattering coefficient due to nitrates = $3[NH_4NO_3]f(RH)$
- b_{OC} = scattering coefficient due to organic aerosols = 4[OC]
- b_{SOIL}= scattering coefficient due to fine particles = 1[Soil]
- b_{Coarse}= scattering coefficient due to coarse particles = 0.6[Coarse Mass]

Particle absorption from soot is defined as:

- b_{ap} = absorption due to elemental carbon (soot) = 10[EC]

The concentration values (in brackets) are expressed in micrograms per cubic meter. The numeric coefficient at the beginning of each equation is the dry scattering or absorption efficiency in meters-squared per gram. The f(RH) term is the relative humidity adjustment factor.

The total atmospheric extinction can be expressed as:

$$b_{ext} = b_{SO4} + b_{NO3} + b_{OC} + b_{SOIL} + b_{Coarse} + b_{ap} + b_{rayleigh}$$

In this equation, the sulfate (SO4) and nitrate (NO3) components are referred to as hygroscopic components because the extinction coefficient depends upon relative humidity. The other components are non-hygroscopic.

The variation of the effect of relative humidity on the extinction coefficients for SO4 and NO3 can be determined in several ways. According to the BART guideline, monthly f(RH) values should be used.

The CALPUFF modeling techniques in this report will provide ground level concentrations of visibility impairing pollutants. The concentration estimates from CALPUFF are used with the previously shown equations to calculate the extinction coefficient.

As described in the IWAQM Phase 2 Report, the change in visibility is compared against background conditions. The delta-deciview, Δdv, value is calculated from the source's contribution to extinction, b_{source}, and background extinction, $b_{background}$, as follows:

$$\Delta dv = 10\ ln((b_{background} + b_{source})/\ b_{background})$$

3. Source Description

The Craig Station is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units, located at 2101 S. Ranney, in Craig. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), are BART-eligible emissions units. Under a January 2001 Consent Order, the existing ESPs were replaced with baghouses and the wet scrubbers were upgraded. The baghouses control PM emissions and limestone scrubbers control SO_2 emissions. The units use low-NO_x burners to control NO_x emissions. In addition, over-fire air and related NO_x control upgrades are in place to meet the requirements of the Consent Decree (CDPHE, 2005).

4. Emission Estimates

According to the BART guideline, "*The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used, as such emission rates could produce higher than normal effects than would be typical of most facilities. We recommend that States use the 24 hour average actual emission rate from the highest emitting day of the meteorological period modeled, unless this rate reflects periods start-up, shutdown, or malfunction*."

Short-term emission rates (≤24-hours) for SO_2, NOx, and PM10 (including condensible and filterable direct PM10[2]) were modeled since visibility impacts are calculated for a 24-hour averaging period. All BART-eligible units at the facility were modeled together in CALPUFF. The Division initially used allowable emission rates or federally enforceable emission limits. If 24-hour emissions limits did not exist, limits of a different averaging period were used. Specifically, if limits did not exist, maximum hourly emissions based on emission factors and design capacity were used.

If the source operator elects to develop emission rates for future subject-to-BART modeling, case-by-case procedures should be developed in consultation with the Division. In general, the following emission rates are acceptable:

- Short-term (≤24-hours) allowable emission rates (e.g., emission rates calculated using the maximum rated capacity of the source).
- Federally enforceable short-term limits (≤24-hours).
- Peak 24-hour actual emission rates (or calculated emission rates) from the most recent 3 to 5 years of operation that account for "high capacity utilization" during normal operating conditions and fuel/material flexibility allowed under a source's permit. In situations where a unit is allowed to use more than one fuel, the fuel resulting in the highest emission rates should be used for the modeling, even if that fuel has not been used in the last 3 to 5 years.

If short-term rates are not available, emissions rates based on averaging periods longer than 24-hours are acceptable only in cases where the modeling shows that the source has impacts equal to or greater than the contribution threshold.

For Craig units 1 and 2, the modeled emission rates are shown in Table 1. The stack parameters are based on the best available information in Division files. To simplify the emissions estimation process, only filterable PM10 emissions were used because modeling with SO_2, NOx, and filterable PM10 shows impacts equal to or greater than the contribution threshold. The basis for the emission rates are shown below:

[2] Common speciated PM species for CALPUFF include fine particulate matter (PMF), coarse particulate matter (PMC), soot or elemental carbon (EC), organic aerosols (SOA), and sulfate (SO4). H_2SO_4, for example, is a PM10 species emitted from coal-fired units that is typically modeled as SO4 in CALPUFF.

- PM: 0.03 lb/mmBtu heat input - January 2001 Consent Decree
- SO_2 : 0.160 lb/mmBtu heat input on a 30 day rolling average - January 2001 Consent Decree
- NOx: 0.34 lbs/mmBtu heat input when burning coal, as estimated by the source operator to reflect peak 24 hour average emissions

Table 1. Stack parameters and emission rates.

Craig Station
Unit 1

Stack Parameters		
Stack height	600	ft
Stack diameter	28	ft
Exit velocity	57.95	ft/s
Exit temperature	118	°F

Source: APEN dated April 27, 2005

Stack Location		
UTM Easting	280421.16	m
UTM Northing	4482341.4	m
Elevation	6345	ft

Source: USGS Aerial Photo, NAD 83, Zone 13 N

Emissions Information		
Design Input Rate	4318	mmBtu/hr
SO_2 Rate (30-day)	0.16	lb/mmBtu
NO_X Rate (3-hr)	0.34	lb/mmBtu
PM_{10} Rate (filterable only)	0.03	lb/mmBtu

Source: Colorado Department of Public Health & Environment

Model Inputs		
Stack height	182.9	m
Stack diameter	8.53	m
Exit velocity	17.66	m/s
Exit temperature	321	K
LCC X Easting	-197.885	km
LCC Y Northing	151.799	km
Elevation	1934	m
SO_2 Rate	87.05	g/s
NO_X Rate	184.98	g/s
PM_{10} Rate	16.32	g/s

Converted with CALPUFF Coords

Craig Station
Unit 2

Stack Parameters		
Stack height	600	ft
Stack diameter	28	ft
Exit velocity	57.95	ft/s
Exit temperature	118	°F

Source: APEN dated April 27, 2005

Stack Location		
UTM Easting	280313.02	m
UTM Northing	4482345.1	m
Elevation	6345	ft

Source: USGS Aerial Photo, NAD 83, Zone 13 N

Emissions Information		
Design Input Rate	4318	mmBtu/hr
SO_2 Rate (30-day)	0.16	lb/mmBtu
NO_X Rate (3-hr)	0.34	lb/mmBtu
PM_{10} Rate (filterable only)	0.03	lb/mmBtu

Source: Colorado Department of Public Health & Environment

Model Inputs		
Stack height	182.9	m
Stack diameter	8.53	m
Exit velocity	17.66	m/s
Exit temperature	321	K
LCC X Easting	-197.996	km
LCC Y Northing	151.802	km
Elevation	1934	m
Converted with CALPUFF Coords		
SO_2 Rate	87.05	g/s
NO_X Rate	184.98	g/s
PM_{10} Rate	16.32	g/s

5. CALMET/CALPUFF Modeling Methodology

In this CALPUFF application, the CALMET/CALPUFF model setup is based on the January 2005 modeling performed by CH2M HILL for the Public Service Company Comanche Unit 3 PSD permit application because it underwent extensive review by the Division and by Federal Land Managers as part of the PSD permitting process. The Division modified the CALPUFF input files to include three additional Class I areas. It has also been modified as necessary to account for PM10 speciation. An additional post-processing step with POSTUTIL has been added to implement ammonia limiting. The CALPOST model setup was changed to make it consistent with the U.S. EPA's BART guideline. In addition, the Division reviewed available data to determine appropriate ammonia background values for various parts of Colorado. The Division also performed sensitivity tests to understand the response of the model to changes in ammonia background concentration levels. Since the currently available version of CALPOST does not generate 98th percentile results, the Division modified CALPOST to generate a file with a full distribution of daily delta-deciview values for each receptor. In addition, the Division wrote a FORTRAN processor to generate 98th percentile results.

This report is intended to provide sufficient technical documentation to support the application of CALPUFF at distances up to 300 kilometers. While CALPUFF has also been used at source-to-receptor distances less than 50 kilometers for some receptors, there is a Class I area within the 50 to 300 km range from every BART-eligible source in Colorado. Impacts at Class I areas greater than 300 km may be used, but it should be recognized that the use of puff splitting in CALPUFF would provide more accurate results for Class I areas beyond 300km.

According to "*Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*" (IWAQM Phase 2 Report):

> *In the context of the Phase 2 recommendation, the focus of the visibility analysis is on haze. These techniques are applicable in the range of thirty to fifty kilometers and beyond from a source. At source-receptor distances less than thirty to fifty kilometers, the techniques for analyzing visual plumes (sometimes referred to as 'plume blight') should be applied.*

For the few cases where BART-eligible source-to-receptors distances are less than 50 kilometers, both the topography and the meteorological fields are complex and the use of CALPUFF appears to be appropriate based on the possibility of recirculation, stagnation, and complex flows. The shortest source-to-receptor distance modeled is about 25 kilometers, but it involves an elevation change of about 3000 ft. In addition, in each case, only a portion of the Class I area is less than 50 km from the source; many of the receptors are greater than 50 km. If there were issues regarding the 50 km distance, PLUVUEII would be an appropriate model to consider for source-to-receptor distances less than 50 kilometers.

5.1. CALMET/CALPUFF Model Selection

The following model versions are used:

- CALPUFF: July 2004 beta version 5.711a, level 040716
- CALMET: July 2004 beta version 5.53a, level 040716
- POSTUTIL: May 2003 version 1.31, level 030528
- CALPOST: July 2003 version 5.51, level 030709
    - Modified by Division for this analysis:
        - CALPOST_BART98_v3.EXE (version 5.51_CO_v3, level 030709)
        - BART98_v3.EXE

The use of CALPUFF is recommended in 40 CFR 51 Appendix Y (BART guideline). The primary niche for CALPUFF is as a long-range transport model. It is a multi-layer, non-steady-state puff dispersion model that can simulate the effects of time- and space-varying meteorological conditions on pollutant transport, chemical transformations, vertical wind shear, and deposition (Scire, 2000).

5.1.1. CALMET

The MM5/CALMET meteorological fields have been generated for 1996, 2001, and 2002. CALMET is based on the Diagnostic Wind Model (Douglas, S. and R. Kessler, 1988). It has been significantly enhanced by Earth Tech, Inc (Scire, 2000). For this particular study, the model uses a Lambert Conformal Projection coordinate system to account for the Earth's curvature.

CALMET uses a two-step approach to calculate wind fields. In the first step, an initial-guess wind field is adjusted for slope flows and terrain blocking effects, for example, to produce a Step 1 wind field. In the second step, an objective analysis is performed to introduce observational data into the Step 1 wind field.

In this application, the initial guess wind fields are based on 36-kilometer MM5[3] meteorological fields for 1996, 2001, and 2002 (i.e., IPROG=14). The MM5 files were provided to the Division by CH2M HILL as part of the Public Service Company (PSCo) Comanche Unit 3 PSD permit application. Alpine Geophysics extracted the MM5 data into a CALMET MM5.DAT format for 1996, 2001, and 2002. Both the 1996 and 2001 MM5 data were generated by the U.S. EPA. The 2002 MM5 data was originally developed for the Visibility Improvement State and Tribal Association of the Southeast (VISTAS).

The BART guideline does not specify the exact number of years of mesoscale meteorological data for use in CALPUFF. According to 40 CFR Part 51 Appendix W, the length of the modeled meteorological period should be long enough to ensure that worst-case meteorological conditions are adequately represented in the model results. The number of years of data needed to obtain a stable distribution of conditions depends on the variable of interest. U.S. EPA recommends that consecutive years from the most recent, readily available 5-year period are preferred. However, “less than five, but at least three,

[3] Fifth-Generation NCAR/Penn State Mesoscale Model.

years of meteorological data (need not be consecutive) may be used if mesoscale meteorological fields are available...."

At the time of this analysis, five years of agency-approved mesoscale meteorological data were not readily available at reasonable grid resolutions for Colorado. While the Division has the national 80km 1990 MM4 and 80km 1992 MM5 data sets, use of the coarse resolution 1990 and 1992 data sets would not improve the accuracy of the modeling results in Colorado.

5.1.1.1. CALMET Modeling Domain

The modeling domain is shown in Figure 1. It is based on a Lambert Conformal Conic projection. As determined by CH2M HILL, the Standard Parallels within the domain are 1/6th and 5/6th of the north-to-south extent instead of the 30-degree and 60-degree lines that are listed as defaults in CALMET. This was done to minimize distortion. See Figure 7 for specific parameter settings.

The domain includes all Class I areas in Colorado with the exception of Mesa Verde NP. Mesa Verde was excluded because it is more than 300 km from all of the BART-eligible sources in Colorado and because the BART-eligible sources in Colorado would have higher impacts at other Class I areas. That is, impacts are Mesa Verde would not be the controlling 98th percentile values for this analysis. The domain does not include Class I areas in any nearby states because the 98th percentile impacts from Colorado's BART-eligible sources are expected to be highest at Class I areas in Colorado. The CALMET domain includes almost the entire state of Colorado. It is about 480 km x 480 km in the longitudinal and meridonal directions, respectively, with 4-kilometer CALMET grid cells.

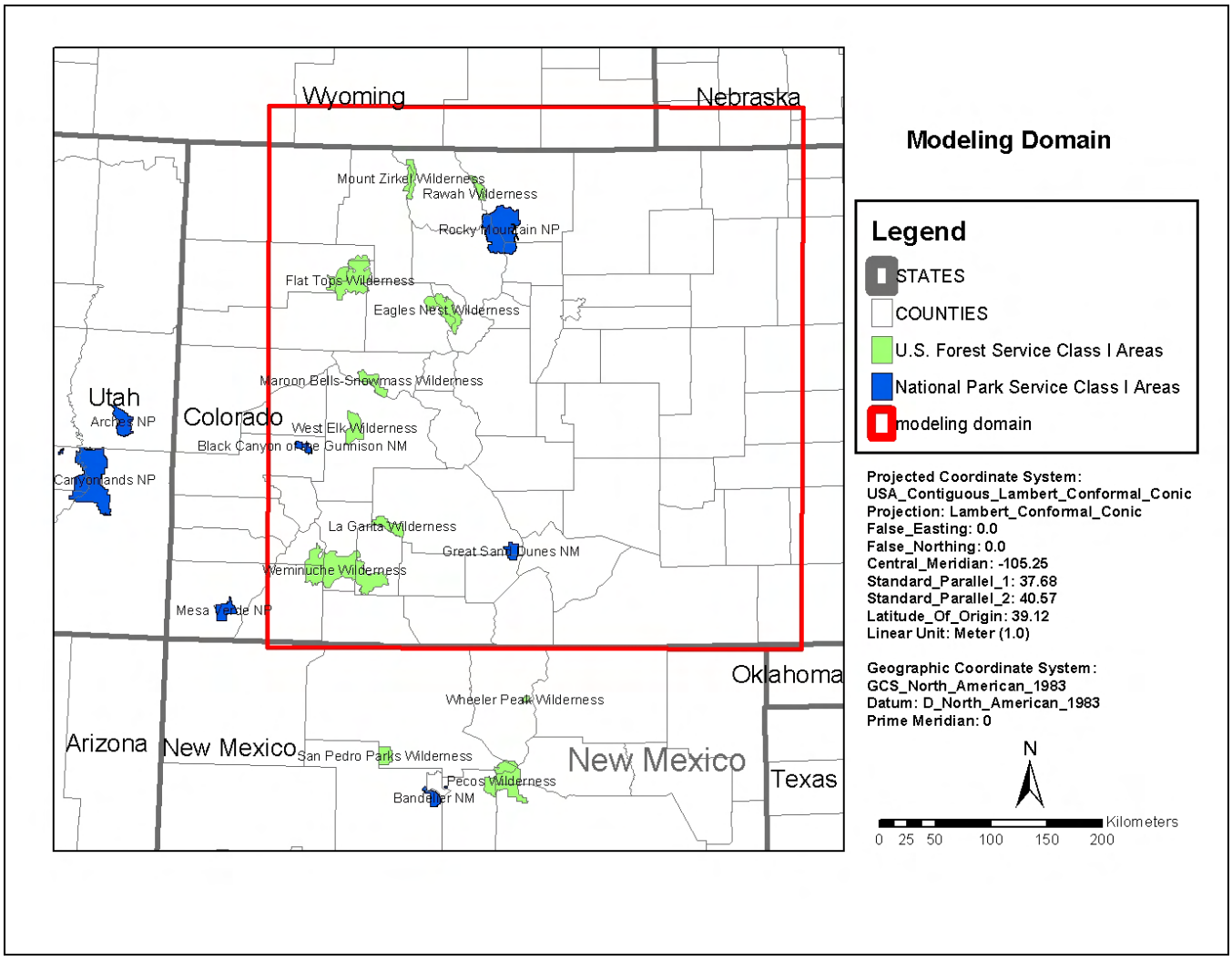

Figure 1. CALMET/CALPUFF modeling domain.

5.1.1.2. CALMET Performance Evaluation

The meteorological fields developed by the MM5/CALMET modeling system were evaluated by CH2M HILL for Xcel Energy as part of the PSCo Comanche Unit 3 PSD permit. Specifically, "CH2M HILL examined vector plots of selected periods within the CALMET output for validation of the wind fields with the CalDESK (Environmodeling Ltda.) program (CH2M HILL, 2005)." The Division replicated the CALMET modeling and performed additional review of the meteorological fields with the Lakes Environmental CALPUFF View software package. In general, the meteorological fields were found to be reasonable given the 36km MM5 resolution, although model performance could be improved with better resolution MM5/CALMET fields and the inclusion of more observations in CALMET.

5.1.1.3. Terrain

Gridded terrain elevations for the modeling domain are derived from 3 arc-second digital elevation models (DEMs) produced by the United States Geological Survey (USGS). The files cover 1-degree by 1-degree blocks of latitude and longitude. USGS 1:250,000 scale DEMs were used. The elevations are in meters relative to mean sea level and have a resolution of about 90 meters, shown in Figure 2.

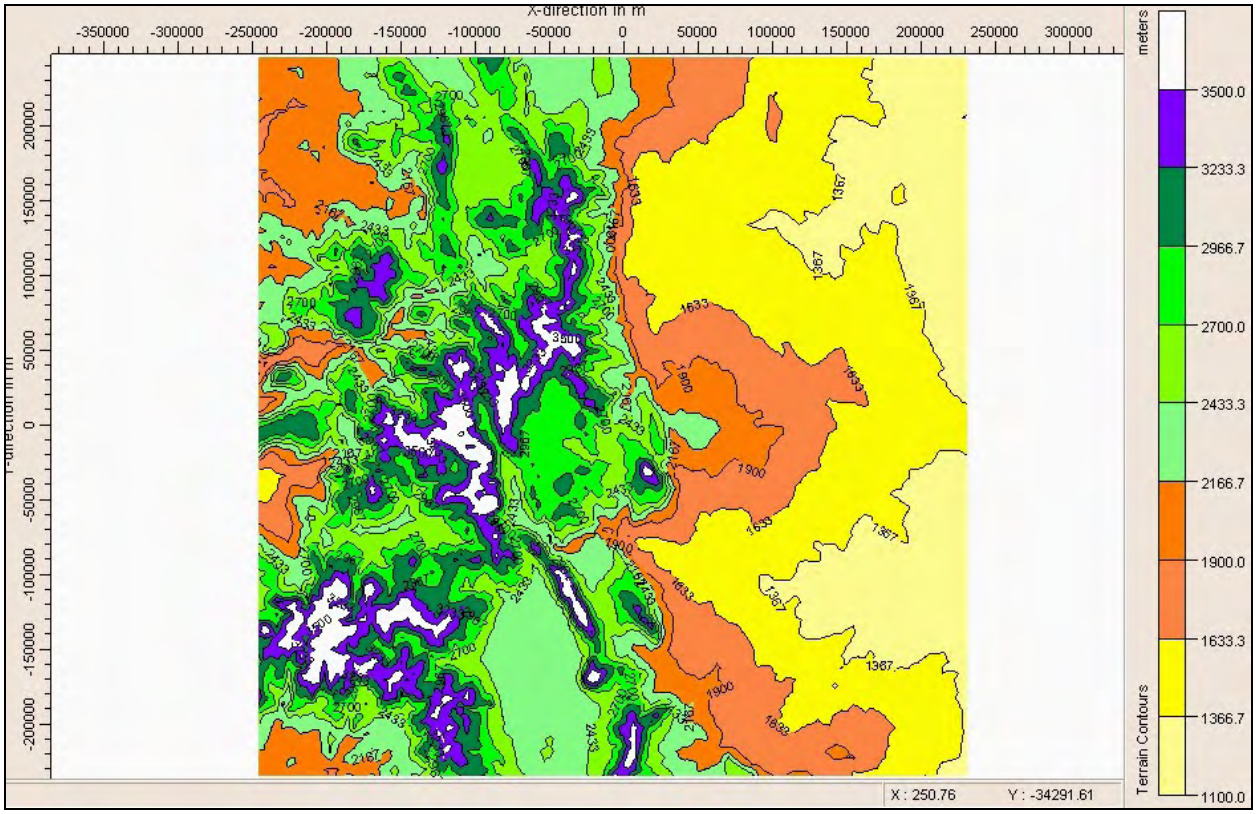

Figure 2. CALMET Terrain.

5.1.1.4. Land Use

The land use data is based on the Composite Theme Grid format (CTG) using Level I USGS land use categories were "mapped into the 14 primary CALMET land use categories (CH2M HILL, 2005)," shown in Figure 3. The land use categories are described in Figure 4.

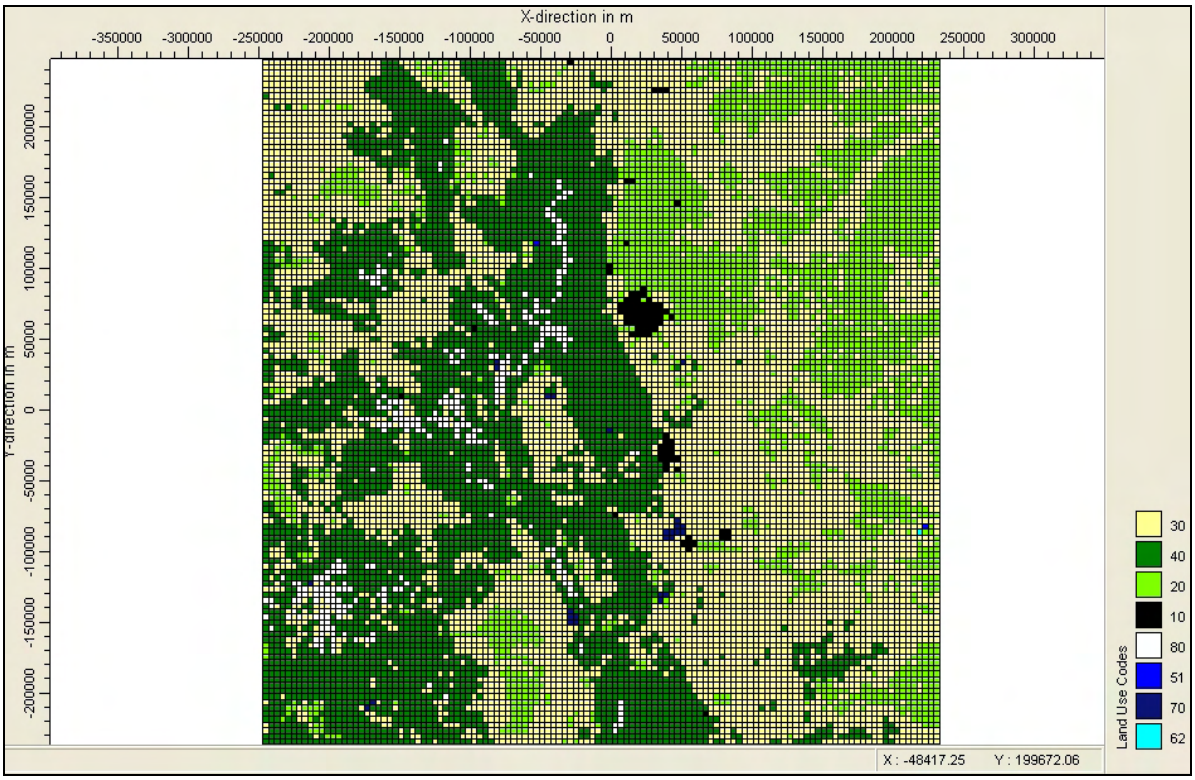

Figure 3. CALMET land use categories.

Default CALMET Land Use Categories and Associated Geophysical Parameters
Based on the U.S. Geological Survey Land Use Classification System
(14-Category System)

Land Use Type	Description	Surface Roughness (m)	Albedo	Bowen Ratio	Soil Heat Flux Parameter	Anthropogenic Heat Flux (W/m^2)	Leaf Area Index
10	Urban or Built-up Land	1.0	0.18	1.5	.25	0.0	0.2
20	Agricultural Land - Unirrigated	0.25	0.15	1.0	.15	0.0	3.0
-20*	Agricultural Land - Irrigated	0.25	0.15	0.5	.15	0.0	3.0
30	Rangeland	0.05	0.25	1.0	.15	0.0	0.5
40	Forest Land	1.0	0.10	1.0	.15	0.0	7.0
51	Small Water Body	0.001	0.10	0.0	1.0	0.0	0.0
54	Bays and Estuaries	0.001	0.10	0.0	1.0	0.0	0.0
55	Large Water Body	0.001	0.10	0.0	1.0	0.0	0.0
60	Wetland	1.0	0.10	0.5	.25	0.0	2.0
61	Forested Wetland	1.0	0.1	0.5	0.25	0.0	2.0
62	Nonforested Wetland	0.2	0.1	0.1	0.25	0.0	1.0
70	Barren Land	0.05	0.30	1.0	.15	0.0	0.05
80	Tundra	.20	0.30	0.5	.15	0.0	0.0
90	Perennial Snow or Ice	.20	0.70	0.5	.15	0.0	0.0

*Negative values indicate "irrigated" land use

Figure 4. Land use categories table from CALMET User's Guide.

5.1.1.5. CALMET ZFACE and ZIMAX Settings

Eleven vertical layers have been used with vertical cell face (ZFACE) heights at: 0, 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, and 5000 meters.

ZIMAX was set to 4500 meters based on analyses of soundings for summer ozone events. The analysis suggests mixing heights in Denver are often well above the CALMET default value of 3000 meters during the summer. For example, on some summer days, ozone levels are elevated all the way to 6000 meters MSL or beyond during some meteorological regimes, including some regimes associated with high ozone episodes. A sounding from the evening of July 1, 2002 (see Figure 5), which is a day the 8-hour ozone standard was exceeded at Rocky Mountain National Park, suggests the mixing height was probably around 6000 meters MSL. The mixing height estimate is based on the relative uniformity of the water vapor mixing ratio below 6000 meters, the temperature profile, the inverted "V" in the sounding, and data from a NOAA ozonesonde from Boulder that shows relatively constant ozone levels with height. Although low mixing heights can occur during the summer, maximum summertime daytime mixing heights in the Denver area often range from about 12,000 feet (3700 m) to 20,000 feet (6000 m) MSL. Since the CALMET ZIMAX setting is above ground level (AGL), not above mean sea level (MSL), the maximum summer daytime mixing height range over the plains would be about 15000 feet (4500 m) AGL. Thus, a ZIMAX setting of 4500 m is used.

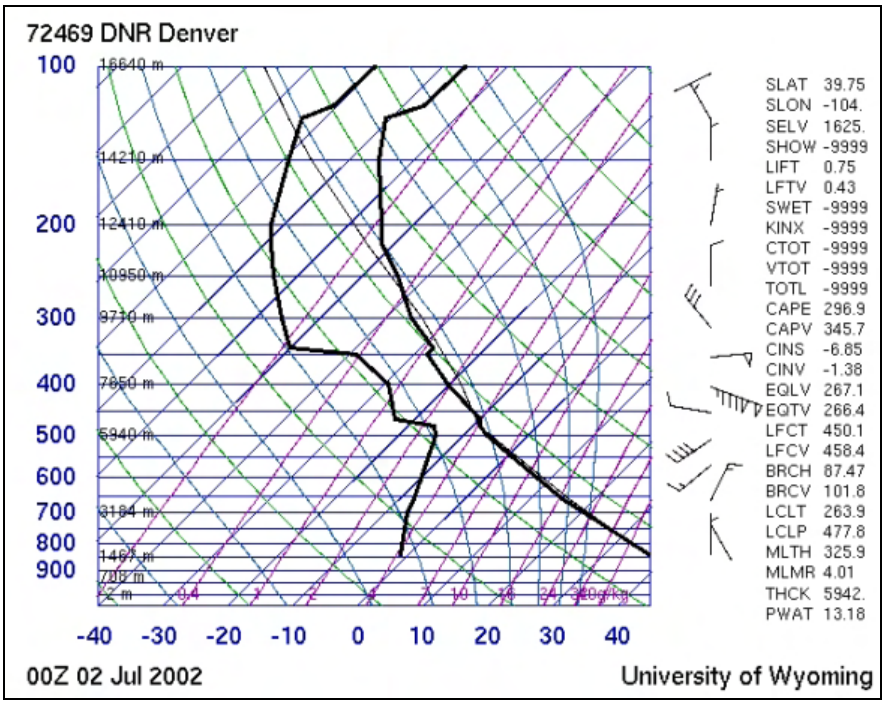

Figure 5. Example Denver summertime sounding.

5.1.1.6. CALMET BIAS Setting

The BIAS settings for each vertical cell determine the relative weight given to the vertically extrapolated surface meteorological observations and upper air soundings. The initial guess field is computed with an inverse distance weighting of the surface and upper air data. It can be modified by the layer-dependent bias factor (BIAS). The values for BIAS can range from –1.0 to 1.0. For example, if BIAS is set to +0.25, the weight of the surface wind observation is reduced by 25%. If BIAS is set to –0.25, the weight of the upper air wind observation is reduced by 25%. If BIAS is set to zero, there is no change in the weighting from the normal inverse distance squared weighting. As recommended by the NPS, the default values of 0.0 have been used for all 11 vertical layers in this analysis.

5.1.1.7. CALMET RMIN2 and IXTERP Settings

Vertical extrapolation of data from a surface station is skipped if the surface station is close to the upper air station. The variable RMIN2 sets the distance between an upper air station and a surface station that must exceeded in order for the extrapolation to take place. RMIN2 has been set to the default value of 4, as recommended by the NPS. The default value of –4 for IEXTRP is used. By setting IEXTRP to –4 (as opposed to +4), layer 1 data at upper air stations is ignored. When IEXTRP=±4, the van Ulden and Holtslag wind extrapolation method is used. The method uses similarity theory and observed data to extend the influence of the surface wind speed and direction aloft.

5.1.1.8. CALMET Settings: R1, R2, RMAX1, RMAX2, RMAX3

An inverse-distance method is used to determine the influence of observations in the Step 1 wind field. R1 controls weighting of the surface layer and R2 controls weighting of the layers aloft. For example, R1 is the distance from an observational station at which the observation and first guess field are equally weighted. In addition, RMAX1, RMAX2, and RMAX3 determine the radius of influence over land in the surface layer, over land in layers aloft, and over water, respectively. That is, an observation is excluded if the distance from the observational site to a given grid point exceeds the maximum radius of influence. As recommended by the NPS, R1 and RMAX1 have been set to 30 km so that the initial guess field does not overwhelm the surface observations. R2 is set to 50 km and RMAX2 is set to 100 km. RMAX3 is not much of a factor in Colorado given the lack of large water bodies. RMAX3 is set to 500 km.

5.1.1.9. CALMET Surface Stations

Eleven surface stations shown in Figure 6 were used, including Alamosa (ALS), Colorado Springs (CYS), Denver (DEN), Eagle (EGE), Limon (LIC), Pueblo (PUB), Trinidad (TAD), Cheyenne (CYS), Laramie (LAR), Rocky Mountain NP (ROM), and Gothic (GTH).

SURFACE STATIONS

Name	ID	X (km)	Y (km)	NLatitude (Deg)	WLongitude (Deg)	Time Zone	Anemometer Height (m)	Grid Coordinates X (Origin = (0,0))	Y
ALS	23061	-54.7	-187.7	37.427	105.868	7.0	9.1	48.061	12.333
CYS	24018	37.7	225.8	41.153	104.801	7.0	10.0	71.166	115.698
COS	93037	49.4	-33.2	38.820	104.681	7.0	6.7	74.086	50.952
DEN	3017	51.2	79.1	39.831	104.652	7.0	10.0	74.549	79.020
ROM	11111	-25.0	128.8	40.280	105.544	7.0	10.0	55.491	91.438
EGE	24675	-142.9	60.2	39.651	106.916	7.0	10.0	26.018	74.305
GTH	22222	-150.0	-16.8	38.956	106.981	7.0	10.0	24.239	55.053
LAR	25645	-35.1	244.6	41.323	105.669	7.0	10.0	52.976	120.412
LIC	24665	131.8	7.8	39.180	103.724	7.0	10.0	94.699	61.195
PUB	93058	65.4	-93.1	38.279	104.502	7.0	10.0	78.106	35.978
TAD	24645	81.4	-205.2	37.267	104.332	7.0	10.0	82.099	7.940

Figure 6. Surface meteorological stations.

5.1.1.10. CALMET Upper Air Stations

Two upper air stations were included: Grand Junction and Denver.

5.1.1.11. CALMET Precipitation Stations

CH2M HILL obtained precipitation data from the National Climatic Data Center (NCDC). All available data in fixed-length, TD-3240 format were ordered for the modeling domain. CH2M HILL processed the data with the PXTRACT and PMERGE processors. Stations with incomplete or poor quality data for a given year were excluded. The number of stations used for each year is as follows (CH2M HILL, 2005):

- 1996 - 84 stations
- 2001 - 82 stations
- 2002 - 86 stations

5.1.1.12. CALMET Sample Input File

Figure 7 summarizes some of the key CALMET parameters.

5.1.1.13. CALMET Parameter Summary

Figure 7 summarizes some of the key CALMET settings.

```
Map projection                                          Default: UTM     ! PMAP = LCC !
Latitude and Longitude (decimal degrees) of projection origin            ! RLAT0 = 39.12N !
                                                                         ! RLON0 = 105.25W !
Matching parallel(s) of latitude (decimal degrees) for projection        ! XLAT1 = 37.68N !
                                                                         ! XLAT2 = 40.57N !
(DATUM)                                             Default: WGS-G       ! DATUM = NAS-C  !
No. X grid cells (NX)                               No default           ! NX =   120  !
No. Y grid cells (NY)                               No default           ! NY =   121  !
Grid spacing (DGRIDKM)                              No default           ! DGRIDKM = 4. !
Reference grid coordinate of SW corner of grid cell (1,1)                ! XORIGKM = -246.984 !
                                                                         ! YORIGKM = -237.000 !
No. of vertical layers (NZ)                         No default           ! NZ =  11  !
Cell face heights in arbitrary vertical grid (ZFACE(NZ+1)):
   ! ZFACE = 0.,20.,100.,200.,350.,500.,750.,1000.,2000.,3000.,4000.,5000.!
NO OBSERVATION MODE                        (NOOBS)  Default: 0           ! NOOBS = 0  !
Number of surface stations                 (NSSTA)  No default           ! NSSTA =  11  !
Number of precipitation stations           (NPSTA)  No default           ! NPSTA =  86  !
Griddid cloud fields:                     (ICLOUD)  Default: 0           ! ICLOUD =  0  !
Model selection variable (IWFCOD)                   Default: 1           ! IWFCOD =  1  !
Compute Froude number adjustment effects ? (IFRADJ) Default: 1           ! IFRADJ =  1  !
Compute kinematic effects ?               (IKINE)   Default: 0           ! IKINE  =  0  !
Use O'Brien procedure?                              Default: 0           ! IOBR =  0  !
Compute slope flow effects ?               (ISLOPE) Default: 1           ! ISLOPE  =  1  !
Extrapolate surface wind obs to upper layers?       Default: -4          ! IEXTRP =  -4  !
Extrapolate surface winds even if calm? (ICALM)     Default: 0           ! ICALM  =  0  !
Layer-dependent biases. Default: NZ*0         ! BIAS =  0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0  !
                                                    Default: 4.          ! RMIN2 = 4 !
Use gridded prognostic wind field model output fields as input to the diagnostic
  wind field model (IPROG)                          Default: 0           ! IPROG =  14  !
Maximum radius of influence over land in the surface layer               ! RMAX1 = 30. !
Maximum radius of influence over land aloft (RMAX2)                      ! RMAX2 = 100. !
Maximum radius of influence over water                                   ! RMAX3 = 500. !
Minimum radius of influence used in the wind field interpolation (RMIN)
                                                    Default: 0.1         ! RMIN = 0.1 !
Radius of influence of terrain features (TERRAD)    No default           ! TERRAD = 40. !
Relative weighting of the first guess field and observations in the SURFACE layer
                                                    No default           ! R1 = 30. !
Relative weighting of the first guess field and observations in the layers ALOFT
                                                    No default           ! R2 = 50. !
Minimum overland mixing height                      Default:  50.        ! ZIMIN = 50. !
Maximum overland mixing height                      Default: 3000.       ! ZIMAX = 4500. !
Interpolation type (1 = 1/R ; 2 = 1/R**2)           Default:1            ! IRAD =  1  !
Radius of influence for temperature interpolation   Default: 500.       ! TRADKM = 500. !
```

Figure 7. CALMET parameter summary.

5.1.2. CALPUFF

The default technical options in CALPUFF were used, except as specified otherwise in this report.

5.1.2.1. Receptor Network and Class I Federal Areas

The modeling domain contains eleven Class I federal areas:

- Flat Tops Wilderness Area
- Rawah Wilderness Area
- Mt Zirkel Wilderness Area
- Weminuche Wilderness Area
- Rocky Mountain National Park
- Maroon Bells-Snowmass Wilderness Area
- La Garita Wilderness Area
- Great Sand Dunes National Park
- West Elk Wilderness Area
- Eagles Nest Wilderness Area
- Black Canyon of the Gunnison National Park

The discrete receptors for eight of the Class I federal areas were generated by the National Park Service (NPS) for CH2M HILL using the *NPS Convert Class I Areas* (NCC) computer program. For the remaining three areas not included in the CH2M HILL modeling, receptors were generated by the Division with the NCC program. Receptor elevations provided by the NPS conversion program have been used. The receptors for each Class I area are shown in Figure 9

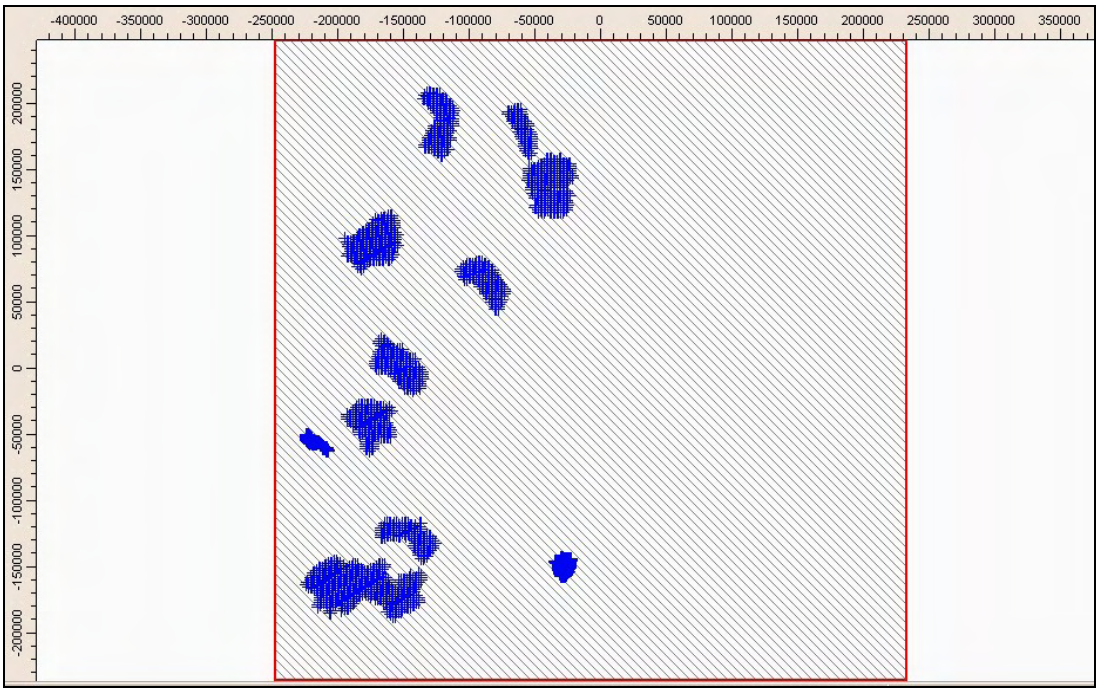

Figure 8. Class I federal area receptors.

All receptors are included in each CALPUFF simulation. In CALPOST, only the receptor ranges for specific Class I areas are processed. The range of receptors is shown in Figure 9.

	Receptors				
Class I Area	**start**	**end**	**leading 0's**	**sum**	**CALPOST setting for NCRECP**
Great Sand Dunes	1	195	0	195	195*1
RMNP	196	602	195	407	195*0, 407*1
La Garita	603	789	602	187	602*0, 187*1
Eagles Nest	790	1002	789	213	789*0, 213*1
Maroon Bells	1003	1281	1002	279	1002*0, 279*1
Weminuche	1282	2025	1281	744	1281*0, 744*1
West Elk	2026	2286	2025	261	2025*0, 261*1
Black Canyon of th	2287	2380	2286	94	2286*0, 94*1
Flat Tops	2381	2735	2380	355	2380*0, 355*1
Rawah	2736	2851	2735	116	2735*0, 116*1
Mt Zirkel	2852	3104	2851	253	2851*0, 253*1

Figure 9. Receptor numbers for specific Class I federal areas.

5.1.2.2. CALPUFF Meteorology

Refer to the CALMET section of the report for details.

5.1.2.3. CALPUFF Modeling Domain

The CALPUFF modeling domain is identical to the CALMET modeling domain.

5.1.2.4. CALPUFF Parameter Summary

Figure 10 summarizes some of the key CALPUFF settings.

```
Number of chemical species (NSPEC)                    Default: 5       ! NSPEC =  7 !
Number of chemical species emitted (NSE)              Default: 3       ! NSE =    5 !
(AVET)                                                Default: 60.0    ! AVET = 60. !
(PGTIME)                                              Default: 60.0    ! PGTIME = 60. !
Vertical distribution used in the near field (MGAUSS) Default: 1       ! MGAUSS =  1   !
Terrain adjustment method (MCTADJ)                    Default: 3       ! MCTADJ =  3   !
Subgrid-scale complex terrain flag (MCTSG)            Default: 0       ! MCTSG =   0   !
Near-field puffs modeled as elongated 0 (MSLUG)       Default: 0       ! MSLUG =   0   !
Transitional plume rise modeled?(MTRANS)              Default: 1       ! MTRANS =  1   !
Stack tip downwash? (MTIP)                            Default: 1       ! MTIP =    1   !
Vertical wind shear modeled above stack top? (MSHEAR) Default: 0       ! MSHEAR =  0   !
Puff splitting allowed? (MSPLIT)                      Default: 0       ! MSPLIT =  0   !
Chemical mechanism flag (MCHEM)                       Default: 1       ! MCHEM =   1   !
Aqueous phase transformation flag (MAQCHEM)           Default: 0       ! MAQCHEM =  0  !
Wet removal modeled ? (MWET)                          Default: 1       ! MWET =     1  !
Dry deposition modeled ? (MDRY)                       Default: 1       ! MDRY =     1  !
Method used to compute dispersion coefficients(MDISP) Default: 3       ! MDISP =    3  !
PG sigma-y,z adj. for roughness?                      Default: 0       ! MROUGH =  0  !
Partial plume penetration of elevated inversion?      Default: 1       ! MPARTL =  1  !
Strength of temperature inversion                     Default: 0       ! MTINV =  0  !
PDF used for dispersion under convective conditions?  Default: 0       ! MPDF =  0  !
Sub-Grid TIBL module used for shore line?             Default: 0       ! MSGTIBL = 0  !
Boundary conditions (concentration) modeled?          Default: 0       ! MBCON = 0  !
Configure for FOG Model output?                       Default: 0       ! MFOG =  0   !
Do options specified to see if they conform to regulatory values?      ! MREG =  1   !
    1 = Technical options must conform to USEPA Long Range Transport (LRT) guidance
```

Figure 10. CALPUFF parameter summary.

5.1.2.5. Chemical Mechanism

The MESOPUFF II pseudo-first-order chemical reaction mechanism (MCHEM=1) is used for the conversion of SO_2 to sulfate (SO4) and NOx to nitrate (NO4). Refer to the CALPUFF User's Guide for a description of the mechanism (Scire, 2000).

In the MESOPUFF II mechanism, the ammonia background concentration affects the equilibrium between nitric acid, ammonia, and ammonium nitrate. The equilibrium constant for the reaction is a non-linear function of temperature and relative humidity (Scire, 2000). Unlike sulfate, the calculated nitrate concentration is limited by the amount of available ammonia, which is preferentially scavenged by sulfate (Scire, 2000). In particular, the amount of ammonia available for the nitric acid, ammonium nitrate, and ammonia reactions is determined by subtracting sulfate from total ammonia.

While the chemical mechanism simulates both the gas phase and aqueous phase conversion of SO_2 to sulfate, the aqueous phase method, which is important when the plume interacts with clouds and fog, can significantly underestimate sulfate formation. In this report, as recommended by the IWAQM Phase 2 report, the "nighttime SO_2 loss rate (RNITE1)" is set to 0.2 percent per hour. The "nighttime

NOx loss rate (RNITE2)" is set to 2.0 percent per hour and the "nighttime HNO_3 formation rate (RNITE3)" is set to 2.0 percent per hour.

According to the 1996 "Mt. Zirkel Wilderness Area Reasonable Attribution Study of Visibility Impairment. Volume II: Results of Data Analysis and Modeling - Final Report,"

The CALPUFF chemical module is formulated around linear transformation rates for SO_2 to sulfate and NO_X to total nitrate. There are two options for specifying these transformation rates:

Option 1: An internal calculation of rates based on local values for several controlling variables (e.g., solar radiation, background ozone, relative humidity, and plume NO_X) as used in MESOPUFF-II. The parametric transformation rate relationships employed were derived from box model calculations using the mechanism of Atkinson et al. (1982).

Option 2: A user-specified input file of diurnally varying but spatially uniform conversion rates.

Morris et al. (1987) reviewed the MESOPUFF-II mechanism as part of the U.S. EPA Rocky Mountain Acid Deposition Model Assessment study. They found that it provided physically plausible responses to many of the controlling environmental parameters. However, the mechanism had no temperature dependence, which is an important factor in the Rocky Mountain region where there are wide variations in temperature. Furthermore, the MESOPUFF-II transformation scheme was based on box model simulations for conditions more representative of the Eastern U.S. than of the Rocky Mountains.

The largest deficiency in the MESOPUFF-II chemical transformation algorithm is the lack of explicit treatment for in-cloud (aqueous-phase) enhanced oxidation of SO_2 to sulfate. The MESOPUFF-II chemical transformation algorithm includes a surrogate reaction rate to account for aqueous-phase oxidation of SO_2 to sulfate as follows:

$$K_{aq} = 3 \times 10^{-8} \times RH^4 \text{ (\%/hr)} \qquad \text{(B.2-1)}$$

Thus, at 100% relative humidity (RH), the MESOPUFF-II aqueous-phase surrogate SO_2 oxidation rate will be 3% per hour. Measurements in generating station plumes suggest spatially- and temporally-integrated SO_2 oxidation rates due to oxidants in clouds to be 10 times this value.

Another issue is the amount of ammonia available for nitrate chemistry. According to a paper by EarthTech (Escoffier-Czaja and Scire, 2002),

"In the CALPUFF model, total nitrate (TNO3 = HNO3 + NO3) is partitioned into each species according to the equilibrium relationship between HNO3 and NO3. This equilibrium varies as a function of time and space, in response to both the ambient temperature and relative humidity. In addition, the formation of nitrate is subject to the availability of NH3 to form ammonium nitrate (NH4NO3), the assumed form of nitrate in the model. In CALPUFF, a continuous plume is simulated as a series of puffs, or discrete plume elements. The total concentration

at any point in the model is the sum of the contribution of all nearby puffs from each source. Because CALPUFF allows the full amount of the specified background concentration of ammonia to be available to each puff for forming nitrate, the same ammonia may be used multiple times in forming nitrate, resulting in an overestimate of nitrate formation. In order to properly account for ammonia consumption, a program called POSTUTIL was introduced into the CALPUFF modeling system in 1999. POSTUTIL allows total nitrate to be repartitioned in a post-processing step to account for the total amount of sulfate scavenging ammonia from all sources (both project and background sources) and the total amount of TNO3 competing for the remaining ammonia. In POSTUTIL, ammonia availability is computed based on receptor concentrations of total sulfate and TNO3, not on a puff-by-puff basis."

Ammonia-limiting methods have been used for repartitioning nitric acid and nitrate on a receptor-by-receptor and hour-by-hour basis to account for over prediction due to overlapping puffs in CALPUFF. Specifically, the use of the MNIRATE=1 option in POSTUTIL is acceptable. At this time, other ammonia-limiting methods, including iterative techniques that use observational data to resolve backward the thermodynamic equilibrium equation between NO_3/HNO_3 for each hour to minimize available ammonia, are not acceptable. Generally, for regulatory CALPUFF modeling in Colorado, techniques that assume the atmosphere is always ammonia poor are not acceptable, particularly in eastern Colorado.

5.1.2.6. Chemical Mechanism – Ammonia Sensitivity Tests

To better understand the response of the modeling system to background ammonia when a single point source with significant emissions of SO_2 and NOx is modeled, the Division performed sensitivity tests for a source in northeast Colorado and a source in northwest Colorado using the 2002 MM5/CALMET meteorology. In the test case, SO_2, NOx, and filterable PM10 emissions were modeled. The ammonia background value was varied from 0 to 100 ppb. In the northeast Colorado test case, the SO_2 emission rate is about 3 times higher than the NOx emission rate. In the northwest Colorado test case, the modeled NOx emission rate is about 4.4 times higher than the SO_2 rate.

In both cases, when the background ammonia concentration is zero, the model produces no nitrate, as expected; however, it produces sulfate.

For the northeast Colorado sensitivity test (see Figure 11), where the modeled SO_2 emission rate is significantly higher than the NOx emission rate, the change in visibility (delta-deciview) is not very sensitive to the background ammonia concentration across the range from 1.0 ppb to 100.0 ppb because of the high SO_2 emission rates relative to NOx and the way sulfate is produced in the MESOPUFF II chemical mechanism. Visibility impacts drop significantly when the ammonia background is less than 1.0 ppb, but even at 0.0 ppb of ammonia, sulfate impacts remain relative high.

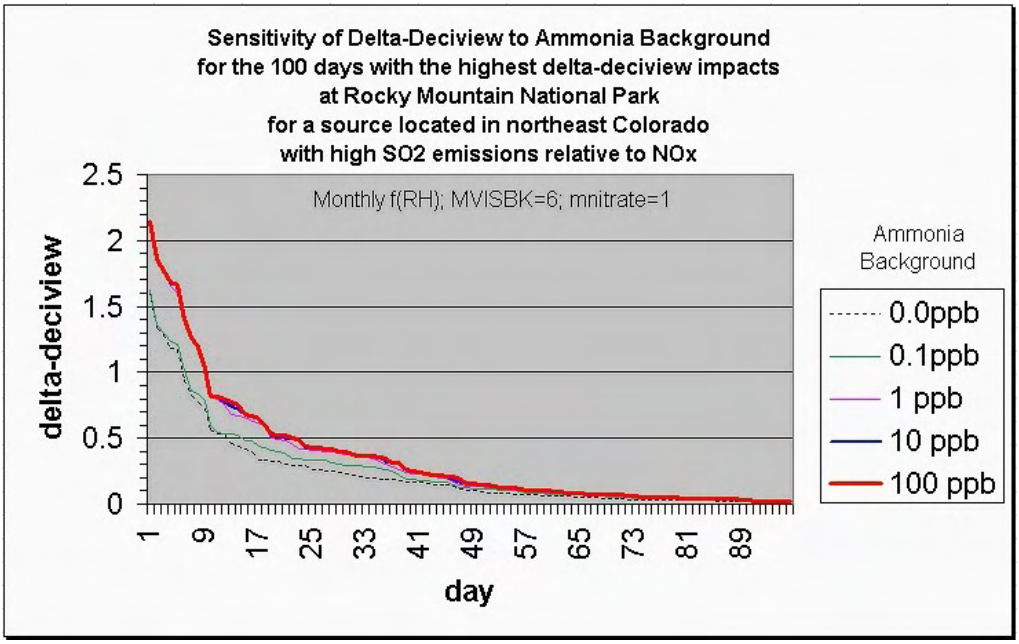

Figure 11. Sensitivity of CALPUFF visibility impacts (delta-deciview) to ammonia backgrounds from 0 ppb to 100 ppb from a source with high SO_2 emissions relative to NOx.

For the northeast Colorado case, on days with the highest visibility impacts, the relative contribution of nitrate and sulfate vary (see Figure 12 and Figure 13), but most of the modeled visibility impairment is due to sulfate. When comparing these figures, be aware the relative rank for some days is different. For example, day 85 is the 2nd worst day for the 0.1 ppb ammonia case, but it's the 3rd worst day for the 100 ppb case. On the day with the highest impact (day 84), the contribution from sulfate is 98.8% for the 0.1 ppb ammonia case and 72.7% for the 100 ppb ammonia case. For the 8th high delta-deciview value, the contribution from sulfate is 86.3% for the 0.1 ppb case and 67.9% for the 100 ppb case.

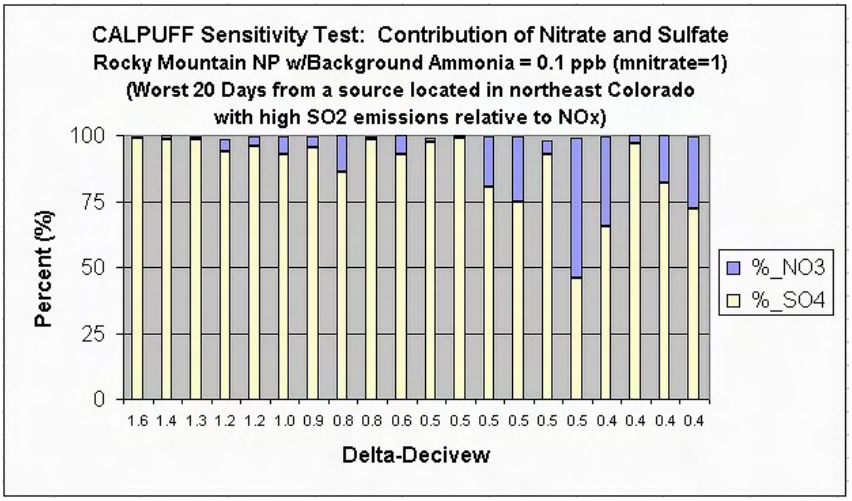

Figure 12. Contribution of sulfate and nitrate to the modeled change in deciviews, assuming a background ammonia of 0.1 ppb in CALPUFF.

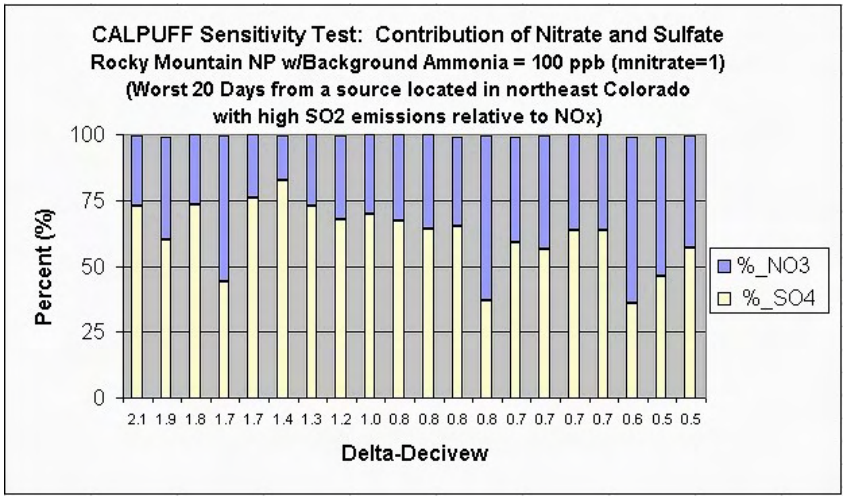

Figure 13. Contribution of sulfate and nitrate to the modeled change in deciviews, assuming a background ammonia of 100 ppb.

For the northwest Colorado sensitivity test (see Figure 14), where the modeled NOx emission rate is significantly higher than the SO_2 emission rate, the change in visibility (delta-deciview) is not sensitive to the background ammonia concentration across the range from 10 ppb to 100 ppb. While there is a moderate drop in impacts when ammonia is dropped from 10 ppb to 1.0 ppb, the model is very sensitive to ammonia when the background ammonia level is less than 1.0 ppb.

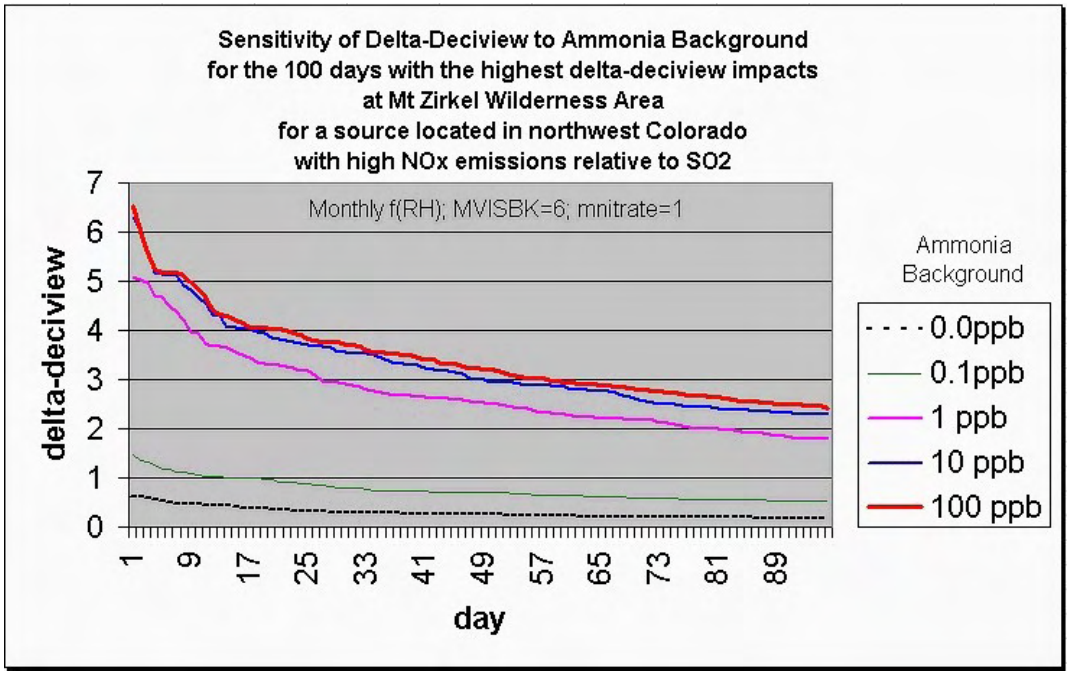

Figure 14. Sensitivity of CALPUFF visibility impacts (delta-deciview) to ammonia backgrounds from 0 ppb to 100 ppb from a source with high NOx emissions relative to SO_2.

For the northwest Colorado test case, according to CALPUFF as implemented here, impairment is primarily due to nitrate (see Figure 15 and Figure 16), but the contribution due to nitrate varies significantly depending on the assumed ammonia background level. For the 100 ppb background case, the nitrate contribution is greater than 90% for the top 20 days. However, for the 0.1 ppb case, the nitrate contribution varies from 43% to 81% for the top 20 days.

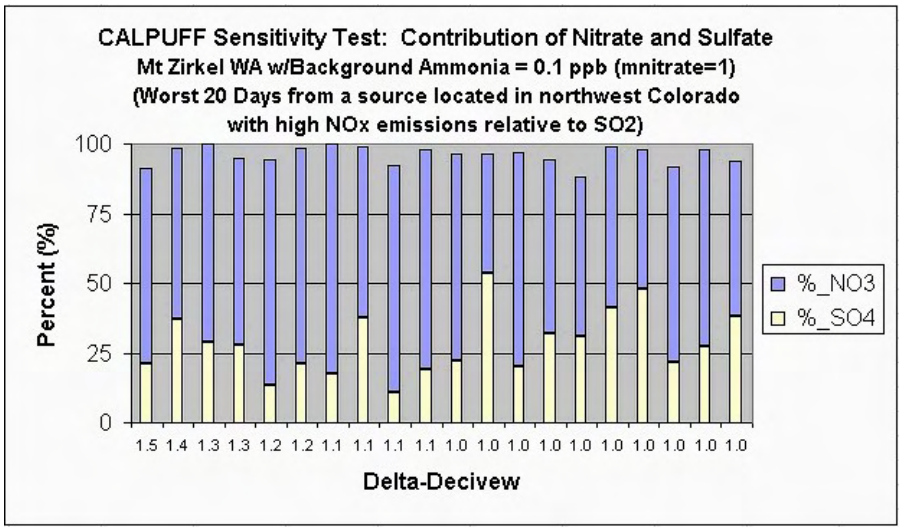

Figure 15. Contribution of sulfate and nitrate to the modeled change in deciviews, assuming a background ammonia of 0.1 ppb in CALPUFF.

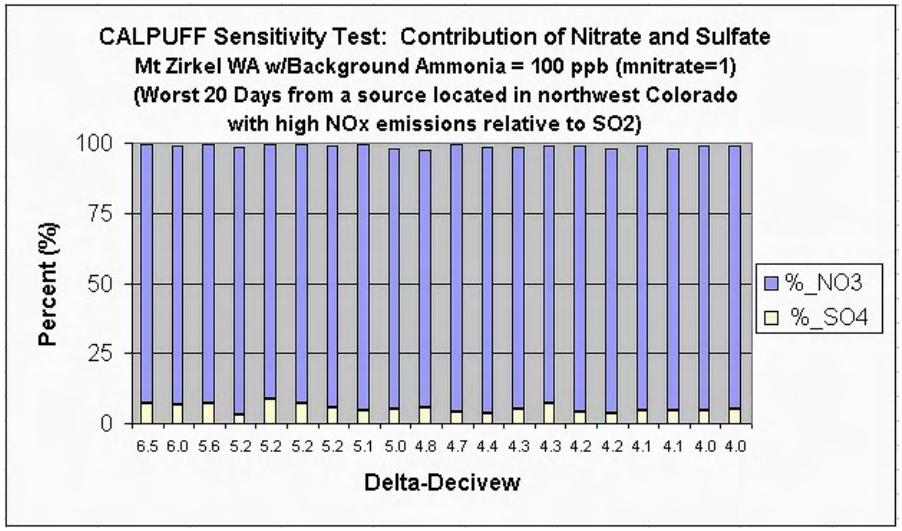

Figure 16. Contribution of sulfate and nitrate to the modeled change in deciviews, assuming a background ammonia of 100 ppb in CALPUFF.

Caution should be used when extrapolating the results of these tests to other CALPUFF applications.

Since the MESOPUFF II chemical mechanism used in this analysis depends on several parameters, including ozone and ammonia background concentrations, the methods for determining the background ozone and ammonia concentration fields are discussed in more detail in the next two sections.

5.1.2.7. Ammonia Assumptions - Discussion

In CALPUFF, as used in this application, the background ammonia concentration is temporally and spatially uniform. It is likely that some portions of the modeling domain are ammonia poor and some are ammonia rich. Thus, setting a domain-wide background is problematic. As discussed in the previous section, when modeling a single large source with high SO_2 emission rates relative to NOx, the assumed background ammonia concentration is not a critical parameter for determining visibility impacts.

According to the IWAQM Phase 2 Report,

> *A further complication is that the formation of particulate nitrate is dependent on the ambient concentration of ammonia, which preferentially reacts with sulfate. The ambient ammonia concentration is an input to the model. Accurate specification of this parameter is critical to the accurate estimation of particulate nitrate concentrations. Based on a review of available data, Langford et al. (1992) suggest that typical (within a factor of 2) background values of ammonia are: 10 ppb for grasslands, 0.5 ppb for forest, and 1 ppb for arid lands at 20 C. Langford et al. (1992) provide strong evidence that background levels of ammonia show strong dependence with ambient temperature (variations of a factor of 3 or 4) and a strong dependence on the soil pH. However, given all the uncertainties in ammonia data, IWAQM recommends use of the background levels provided above, unless specific data are available for the modeling domain that would discredit the values cited. It should be noted, however, that in areas where there are high ambient levels of sulfate, values such as 10 ppb might overestimate the formation of particulate nitrate from a given source, for these polluted conditions. Furthermore, areas in the vicinity of strong point sources of ammonia, such as feed lots or other agricultural areas, may experience locally high levels of background ammonia.*

The Northern Front Range is assumed to be ammonia rich. “Sulfate along the Northern Front Range is completely neutralized by available ammonium and is present in the form of ammonium sulfate....The Northern Front Range is ammonia rich. There was sufficient ammonia, on most days during winter, to completely neutralize available nitric acid (NFRAQS, 1998).”

For northeast Colorado, a background ammonia concentration of 30.4 $\mu g/m^3$ (about 44 ppb) or less appears to be reasonable based on measurements for this modeling study. According to monitoring conducted for NFRAQS,

- *"With respect to gaseous measurements, only ammonia was acquired at all nine sites with the denuder difference method at the Brighton and Welby sites and with the filter-pack method (i.e., impregnated cellulose-fiber filters behind Teflon-membrane filters) at the other sites. Average ammonia concentrations*

were 30.4 ± 53.4 µg/m3 at the core sites and 10.3 ±12.6 µg/m3 at the satellite sites. The large standard deviation is mainly due to elevated ammonia concentrations found at the Evans site. Maximum 24-hour ammonia concentrations were 187.0 ± 5.4 µg/m3 at the Evans core site on 01/17/97 and 66.7 ± 3.5 µg/m3 at the Masters site on 01/20/97. Figure 6.3-5 shows that during the mid-January episode, 24-hour ammonia concentrations varied by orders of magnitude at the nine NFRAQS sites."

- *"For the 6- and 12-hour samples, Figure 6.4-3*[not included in this report] *ammonia concentrations were rather consistent throughout the day, with apparent site -to-site and season-to-season variation. Average ammonia concentrations at the Brighton site were double those at the Welby site during Winter 97. Summertime ammonia concentrations were ~1 to 2 µg/m3 higher than the wintertime at the Welby site. Since ammonia concentrations closely reflect the vicinity of the sampling area, site-to-site variations were more pronounced than seasonal or diurnal variations. This is evidenced by the graph in Figure 6.4-4*[not included in this report], *which shows ammonia concentrations were factors of 10 to 20 higher at the Evans site than at most of the other sites during Winter 97. Elevated concentrations exceeded 50 µg/m3 on 20% of the days at the Evans site. Twenty-four hour ammonia concentrations at the Masters and Longmont sites were also factors of 5 to 10 higher than at the other sites."*

For other areas like northwest Colorado, an annual background ammonia concentration of about 1 ppb or less is probably more reasonable, based on ammonia measurements from the Mt. Zirkel Visibility Study.

In the Aerosol Evolution Model (AEM) simulations done for the Mt Zirkel Study for a specific period, "*base case background air concentrations for ammonia were assumed to be 0.5 µg/m^3 and 30 ppb$_v$ for ozone, consistent with measured values at the Hayden VOR site*." An ammonia concentration of 0.5µg/m^3 is about 0.7 ppb.

In the CALPUFF modeling section of the Mt Zirkel Study report,

"The CALPUFF default value for background ammonia concentrations of 10 ppb was also considered far too high as a representative area-average. Measurements from the Buffalo Pass and Gilpin Creek sites were used to adjust ammonia concentration to episode and site-mean values."

Based on a review of CALUFF files used for the Mt. Zirkel Study, for the August simulations, the assumed ammonia background (BCKNH3) was 1.6 ppb; for the October simulation, the assumed background was 0.5 ppb; and for the September simulation, the assumed background was 0.8 ppb.

5.1.2.8. Ammonia Assumptions

Based on information in the previous section, for sources located in northeast Colorado and along the South Platte River, a domain-wide ammonia background

value of 44 ppb is used. For sources located in northwest Colorado, a background ammonia concentration of 1.0 ppb is used. For sources located in southeastern Colorado and for source located along the Arkansas River, a background value of 10 ppb is used.

5.1.2.9. Ozone Assumptions

According to the IWAQM Phase 2 Report,

> *CALPUFF provides two options for providing the ozone background data: (1) a single, typical background value appropriate for the modeling region, or (2) hourly ozone data from one or more ozone monitoring stations. The second and preferred option requires the creation of the OZONE.DAT file containing the necessary data. For the Demonstration Assessment, the domain was large (700 km by 1000 km) such that the second option was necessary. The IWAQM does not anticipate such large domains as being the typical application. Rather, it is anticipated that the more typical application will involve domains of order 400 km by 400 km or smaller. But even for smaller domains, the ability to provide at least monthly background values of ozone is deemed desirable. The problem in developing time (and perhaps spatial) varying background ozone values is having access to representative background ozone data. Ozone data are available from EPA's Aerometric Information Retrieval System (AIRS); however, AIRS data must be used with caution. Many ozone sites are located in urban and suburban centers and are not representative of oxidant levels experienced by plumes undergoing long range transport.*

In this study, "*CH2M HILL obtained hourly ozone data from the following stations located within the modeling domain for some or all of the years 1996, 2001, and 2002:*

- *Gothic (Gunnison County, Colorado)*
- *Rocky Mountain National Park*

Additional, hourly data for 1996, 2001, and 2002 were provided to CH2M HILL by the APCD for the following stations along the Front Range:

- *Greeley*
- *Highlands Ranch*
- *Colorado Springs*

Data recovery for the years 2001 and 2002 for the Greeley station was very low, and therefore data from the nearby Fort Collins station were used instead. Any data missing from the hourly records were replaced with a domain-wide default concentration of 60 parts per billion (ppb), as determined by the APCD/NPS (CH2M HILL, 2005)."

5.1.3. CALPOST Settings and Visibility Post-Processing

The CALPUFF results have been post-processed with a modified version of CALPOST (version 5.51_CO_v3, level: 030709), POSTUTIL (version 1.31, level 030528), and BART98_v3. The CALPOST modifications were performed by the Division and do not affect any of the calculations in CALPOST for the deciview values used in this report; however, some simple calculations were done within CALPOST in order to output delta-deciview values (instead of percent change values) for the individual species that contribute to the overall delta-deciview value, but these values are not used for the subject-to-BART modeling. Otherwise, the CALPOST code modification consists of a "write" statement and supporting code. It outputs all daily delta-deciview values for every receptor to a file called "deciview24.dat." The 98th percentile values are computed from "deciview24.dat" by a separate FORTRAN processor (BART98_v3) written by the Division specifically for this analysis.

For the initial modeling analysis, all PM10 was assumed to have a extinction efficiency of 1.0 since the contribution of direct PM10 emissions is expected to be relatively small compared to visibility impairment caused by SO_2 and NOx emissions. However, if modeled impacts were below the contribution threshold, condensible and filterable PM10 emissions were quantified and speciated or a sensitivity test was performed to determine if PM10 speciation could change the outcome of the analysis. If speciated PM10 emissions were modeled, the following species were considered: fine particulates (PMF), coarse particulates (PMC), elemental carbon (EC), organic carbon (SOA), and sulfate (SO4). To see how PM10 was modeled for this source, refer to sections 4 and 5.1.3.2.

In this study, to calculate background light extinction, MVISBK has been set to 6. That is, monthly RH adjustment factors are applied directly to the background and modeled sulfate and nitrate concentrations, as recommended by the BART guideline. The RHMAX parameter, which is the maximum relative humidity factor used in the particle growth equation for visibility processing, is not used when method 6 is selected. Similarly, the relative humidity adjustment factor (f(RH)) curves in CALPOST (e.g., IWAQM growth curve and the 1996 IMPROVE curve) are not used when MVISBK is equal to 6.

The natural background is based on the 20 percent best visibility days, as recommended by the BART guideline preamble:

> *Finally, these BART guidelines use the natural visibility baseline for the 20 percent best visibility days for comparison to the "cause or contribute" applicability thresholds. We believe this estimated baseline is likely to be reasonably conservative and consistent with the goal of natural conditions* (70 FR 39125).

The method for estimating natural background is presented in section 5.1.3.1. Specifically, for hygroscopic components, BKSO4 in CALPOST has been set to 0.0893 for all months. For non-hygroscopic components, BKSOIL has been set to 1.620 for all months. The BKSO4 and BKSOIL values have been computed specifically for the Colorado Class I areas in the modeling domain.

The extinction due to Rayleigh scattering (i.e., the scattering of light by natural particles much smaller than the wavelength of the light) has been set to 10 Mm^{-1} (BEXTRAY = 10.0).

5.1.3.1. Natural Conditions - Determining Hygroscopic And Non-Hygroscopic Values For the Best 20% Visibility Days

5.1.3.1.1. Natural Background - Objective

The spreadsheet shown in Figure 17 was created to determine the hygroscopic (3[BKSO4]) and non-hygroscopic (equivalent to [BKSOIL]) portions of natural background for the best 20% visibility days (Best Days) at all Class I areas in Colorado's BART modeling. These concentrations, [BKSO4] and [BKSOIL], are used in CALPOST with monthly relative humidity adjustment factors (f(RH)) to determine monthly natural background visibility that would, on average, represent the average natural background visibility for the best 20% days in EPA's "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" (EPA, 2003).

5.1.3.1.2. Natural Background - Discussion

"Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" (EPA, 2003), section 2.4, describes the calculation of the annual average background extinction (in 1/Mm) for a Class I area using the area's annual f(RH) and average natural concentrations based on the area's geographic location (east versus west). Annual average background extinction values (in 1/Mm) are converted to annual average Haze Index (HI) values (in deciview or dv). Then, the average HI value for the 20% best visibility days (Best Days (dv)) is estimated from 10th percentile of the annual average HI value for a Class I area assuming normal distribution. Thus, no average natural concentrations are provided for determining extinction for the 20% best visibility days.

For background extinction computation methods 2, 3, and 6 in CALPOST, background extinction is calculated with user-supplied monthly concentrations of SO4, NO3, PM coarse, organic carbon, soil, and elemental carbon species. In practice, concentrations for only 2 species, SO4 ([BKSO4]) and soil ([BKSOIL]), are supplied in the CALPOST input file to represent hygroscopic and non-hygroscopic portions of background extinction, respectively.

To determine background extinction for the BART analysis with CALPOST, average natural concentrations that represent average natural background visibility for the best 20% days need to be determined.

5.1.3.1.3. Natural Background - Method

Following EPA's approach of using regional average natural concentrations and the concept of using simplified inputs in CALPOST, the same hygroscopic ($3[BKSO4]_{best20}$) and non-hygroscopic ($[BKSOIL]_{best20}$) values would be used in CALPOST for all Class I areas in Colorado's BART modeling.

The spreadsheet calculates an average background (dv) based on monthly background extinction (1/Mm) for each Class I area in Colorado's BART modeling using the following equations:

1. Monthly background extinction in 1/Mm ($bext_{month}$) = $3[BKSO4]_{best20}f(RH)$ + $[BKSOIL]_{best20}$ + Rayleigh
2. Annual average background extinction in 1/Mm ($bext_{annual_ave}$) = ($bext_{Jan}$ + $bext_{Feb}$ + … + $bext_{Dec}$)/12
3. Calculated Best Days in dv = $10\ln(bext_{annual_ave}/10)$

EPA guidance provides f(RH) values based on the centroid of the Class I area (see Appendix B – Monthly f(RH) Values) and a Best Days (dv) value for each of the Class I areas (see Appendix A – Natural Background Values).

The hygroscopic (3[BKSO4]) and non-hygroscopic ([BKSOIL]) values determined yielded the lowest sum of the absolute differences between the published Best Days (dv) and calculated Best Days (dv) for all Class I areas in the analysis:

where: n = number of Class I areas in analysis

The "hygro (3[BKSO4])" and "non-hygro ([BKSOIL])" values of 0.268 and 1.620 were calculated in Microsoft Excel using the "solver add-in" tool for optimization and equation solving (Figure 17). As can be seen from the “difference” values in Figure 17, the annual 20% best visibility days background concentrations for each Class I area calculated with this method are within 0.01 deciviews or less of the annual 20% best visibility days background values recommended by EPA. For CALPOST, the hygroscopic component of extinction is divided by 3 (the extinction coefficient of sulfate and nitrate) and input as BKSO4 (i.e., BKSO4 = 0.268/3 = 0.0893). The non-hygroscopic component is used directly (i.e., BKSOIL = 1.620).

hygro (3[BKSO4])	**0.268**
non-hygro ([BKSOIL])	**1.620**

	f(RH)											Background Extinction (1/Mm)										
Month	BC	EN	FT	GSD	LG	MB	MZ	RW	RM	WEM	WELK	BC	EN	FT	GSD	LG	MB	MZ	RW	RM	WEM	WELK
1	2.4	2.2	2.3	2.4	2.3	2.2	2.2	2.1	1.7	2.4	2.3	12.3	12.2	12.2	12.3	12.2	12.2	12.2	12.2	12.1	12.3	12.2
2	2.2	2.2	2.2	2.3	2.2	2.1	2.2	2.1	1.9	2.2	2.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.2	12.1	12.2	12.2
3	1.9	2.0	2.0	2.0	1.9	2.0	2.0	2.0	1.9	1.9	1.9	12.1	12.2	12.2	12.2	12.1	12.2	12.2	12.2	12.1	12.1	12.1
4	1.9	2.0	2.0	1.9	1.8	2.0	2.1	2.1	2.1	1.7	1.9	12.1	12.2	12.2	12.1	12.1	12.2	12.2	12.2	12.2	12.1	12.1
5	1.9	2.1	2.0	1.9	1.8	2.1	2.2	2.3	2.3	1.7	1.9	12.1	12.2	12.2	12.1	12.1	12.2	12.2	12.2	12.2	12.1	12.1
6	1.6	1.9	1.8	1.8	1.6	1.7	1.9	2.0	2.0	1.5	1.7	12.0	12.1	12.1	12.1	12.0	12.1	12.1	12.2	12.2	12.0	12.1
7	1.7	1.8	1.7	1.9	1.7	1.9	1.7	1.8	1.8	1.6	1.8	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.0	12.1
8	1.9	2.0	1.9	2.3	2.1	2.2	1.9	2.0	2.0	2.0	2.1	12.1	12.2	12.1	12.2	12.2	12.2	12.1	12.2	12.2	12.2	12.2
9	2.0	2.0	1.9	2.2	2.0	2.1	2.0	2.0	1.9	1.9	2.0	12.2	12.2	12.1	12.2	12.2	12.2	12.2	12.2	12.1	12.1	12.2
10	1.8	1.9	1.8	1.9	1.8	1.8	1.9	1.9	1.8	1.7	1.8	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1
11	2.1	2.1	2.2	2.4	2.2	2.1	2.1	2.1	1.8	2.1	2.1	12.2	12.2	12.2	12.3	12.2	12.2	12.2	12.2	12.1	12.2	12.2
12	2.3	2.1	2.2	2.4	2.3	2.1	2.1	2.0	1.7	2.3	2.2	12.2	12.2	12.2	12.3	12.2	12.2	12.2	12.2	12.1	12.2	12.2
										Annual Ave (dv)		1.95	1.96	1.95	1.98	1.95	1.96	1.96	1.96	1.93	1.93	1.95
										Target Annual Best Days (dv)		1.94	1.96	1.95	1.98	1.94	1.95	1.96	1.96	1.93	1.94	1.95
										Difference		0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.01	0.00
										Sum of Differences		0.039										

Figure 17. Spreadsheet showing the "hygro (3[BKSO4])" (0.268)and "non-hygro ([BKSOIL])" (1.620) values calculated in Microsoft Excel using the "solver add-in" tool for optimization and equation solving.

5.1.3.2. CALPOST and POSTUTIL Parameters

For this modeling analysis, if PM10 speciation was performed (see section 4), then example #1 from this section was used. If PM10 speciation was not performed, then example #2 from this section was used. In example #1, fine particulate emissions are speciated into PMF, PMC, EC, SOA, and SO4 and explicitly included as species in CALPUFF. Emission rates for each species are included in CALPUFF. Figure 18 summarizes some of the key CALPOST settings. The monthly f(RH) values (RHFAC), which are different for each Class I area, are from Appendix B – Monthly f(RH) Values.

```
Modeled species to be included in computing the light extinction
     Include SULFATE?          (LVSO4) -- Default: T   ! LVSO4  = T  !
     Include NITRATE?          (LVNO3) -- Default: T   ! LVNO3  = T  !
     Include ORGANIC CARBON?   (LVOC)  -- Default: T   ! LVOC   = T  !
     Include COARSE PARTICLES? (LVPMC) -- Default: T   ! LVPMC  = T  !
     Include FINE PARTICLES?   (LVPMF) -- Default: T   ! LVPMF  = T  !
     Include ELEMENTAL CARBON? (LVEC)  -- Default: T   ! LVEC   = T  !
Species name used for particulates in MODEL.DAT file
                   COARSE    (SPECPMC) -- Default: PMC ! SPECPMC = PMC !
                   FINE      (SPECPMF) -- Default: PMF ! SPECPMF = PMF !
MODELED particulate species:
               PM  COARSE      (EEPMC) -- Default: 0.6 ! EEPMC  = 0.6 !
               PM  FINE        (EEPMF) -- Default: 1.0 ! EEPMF  = 1.0 !
BACKGROUND particulate species:
               PM  COARSE    (EEPMCBK) -- Default: 0.6 ! EEPMCBK = 0.6 !
Other species:
              AMMONIUM SULFATE (EESO4) -- Default: 3.0 ! EESO4  = 3.0 !
              AMMONIUM NITRATE (EENO3) -- Default: 3.0 ! EENO3  = 3.0 !
              ORGANIC CARBON   (EEOC)  -- Default: 4.0 ! EEOC   = 4.0 !
              SOIL             (EESOIL)-- Default: 1.0 ! EESOIL = 1.0 !
              ELEMENTAL CARBON (EEEC)  -- Default: 10. ! EEEC   = 10.0 !
Method used for background light extinction
                               (MVISBK) -- Default: 2   ! MVISBK =  6  !

(RHFAC)  -- No default      ! RHFAC = 2.4,2.2,1.9,1.7,
                                      1.7,1.5,1.6,2.0,
                                      1.9,1.7,2.1,2.3 !
(BKSO4)  -- No default      ! BKSO4 = 0.0893, 0.0893, 0.0893, 0.0893,
                                      0.0893, 0.0893, 0.0893, 0.0893,
                                      0.0893, 0.0893, 0.0893, 0.0893 !
(BKNO3)  -- No default      ! BKNO3 = 0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0 !
(BKPMC)  -- No default      ! BKPMC = 0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0 !
(BKOC)   -- No default      ! BKOC  = 0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0 !
(BKSOIL) -- No default      ! BKSOIL= 1.620, 1.620, 1.620, 1.620,
                                      1.620, 1.620, 1.620, 1.620,
                                      1.620, 1.620, 1.620, 1.620 !
(BKEC)   -- No default      ! BKEC  = 0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0,
                                      0.0, 0.0, 0.0, 0.0 !
Extinction due to Rayleigh scattering is added (1/Mm)
                               (BEXTRAY) -- Default: 10.0 ! BEXTRAY = 10.0 !
```

Figure 18. CALPOST - key parameters (example #1 setup).

POSTUTIL is used to compute the partition for the total concentration fields with MNITRATE=1 and the appropriate ammonia background concentration. The ammonia background concentration, BCKNH3, in POSTUTIL is the same as the background value presented in section Figure 18. In POSTUIL, the input species include SO2, SO4, NOX, HNO3, NO3, SOA, PMF, PMC, and EC and the output species include SO4, HNO3, NO3, SOA, PMF, PMC, and EC. Key POSTUTIL parameters are shown in Figure 19.

```
Number of species to process from CALPUFF runs
                          (NSPECINP) -- No default    ! NSPECINP = 9 !
Number of species to write to output file
                          (NSPECOUT) -- No default    ! NSPECOUT = 7 !
Number of species to compute from those modeled
      (must be no greater than NSPECOUT)
                          (NSPECCMP) -- No default    ! NSPECCMP = 0 !
Number of CALPUFF data files that will be scaled
      (must be no greater than NFILES)
      (NSCALED)                      Default: 0       ! NSCALED = 0 !
Recompute the HNO3/NO3 partition for concentrations?
      (MNITRATE)                     Default: 0       ! MNITRATE  =  1  !
The following NSPECINP species will be processed:

 ! ASPECI =            SO4  !          !END!
 ! ASPECI =            SO2  !          !END!
 ! ASPECI =            NOx  !          !END!
 ! ASPECI =            NO3  !          !END!
 ! ASPECI =            HNO3 !          !END!
 ! ASPECI =            PMF  !          !END!
 ! ASPECI =            PMC  !          !END!
 ! ASPECI =            EC   !          !END!
 ! ASPECI =            SOA  !          !END!


The following NSPECOUT species will be written:

 ! ASPECO =             SO4  !          !END!
 ! ASPECO =             NO3  !          !END!
 ! ASPECO =             HNO3 !          !END!
 ! ASPECO =             PMF  !          !END!
 ! ASPECO =             PMC  !          !END!
 ! ASPECO =             EC   !          !END!
 ! ASPECO =             SOA  !          !END!
```

Figure 19. POSTUTIL - key parameters for cases with nitrate partitioning and speciated PM10 concentrations (example #1 setup).

In example #2, PM10 is included as a species in CALPUFF and ammonia limiting is performed. The CALPOST setup is the same as the example #1 setup (see Figure 18) except LVPMC=F, since there are is no coarse PM, and SPECPMF=SOIL because the PM10 emissions from CALPUFF are reallocated to the species SOIL and EC in the first of two POSTUTIL runs. The first POSTUTIL setup (see Figure 20) was intended to provide a post-processing opportunity to divide the PM10 concentrations into SOIL and EC components; however, in the setup shown in Figure 20, all of the PM10 was allocated to SOIL and none was allocated to EC.

```
Number of species to process from CALPUFF runs
                          (NSPECINP) -- No default    ! NSPECINP = 5 !
Number of species to write to output file
                          (NSPECOUT) -- No default    ! NSPECOUT = 6 !
Number of species to compute from those modeled
      (must be no greater than NSPECOUT)
                          (NSPECCMP) -- No default    ! NSPECCMP = 2 !
Recompute the HNO3/NO3 partition for concentrations?
      (MNITRATE)                    Default: 0       ! MNITRATE  =  0  !
The following NSPECINP species will be processed:
 ! ASPECI =          SO4 !          !END!
 ! ASPECI =          NO3 !          !END!
 ! ASPECI =         HNO3 !          !END!
 ! ASPECI =         PM10 !          !END!
 ! ASPECI =          SOA !          !END!

The following NSPECOUT species will be written:
 ! ASPECO =            SO4  !          !END!
 ! ASPECO =            NO3  !          !END!
 ! ASPECO =           HNO3  !          !END!
 ! ASPECO =             EC  !          !END!
 ! ASPECO =           SOIL  !          !END!
 ! ASPECO =            SOA  !          !END!

The following NSPECCMP species will be computed by scaling and summing
one or more of the processed input species.  Identify the name(s) of
the computed species and provide the scaling factors for each of the
NSPECINP input species (NSPECCMP groups of NSPECINP+1 lines each):

 ! CSPECCMP =     EC !
 !     SO4  =     0.0      !
 !     NO3  =     0.0      !
 !    PM10  =     0.00  !
 !     SOA  =     0.0      !
 !END!

 ! CSPECCMP =     SOIL !
 !     SO4  =     0.0      !
 !     NO3  =     0.0      !
 !    PM10  =     1.0  !
 !     SOA  =     0.0      !
 !END!
```

Figure 20. POSTUTIL setup for simulations where PM10 is divided into SOIL and EC species (example #2 setup).

In the second POSTUTIL setup for example#2, POSTUTIL is used to compute the partition for the total concentration fields with MNITRATE=1 and the appropriate ammonia background concentration. The ammonia background concentration, BCKNH3, in POSTUTIL is the same as the background value presented in section 5.1.2.8. In this POSTUIL setup, the input species include SO4, NO3, HNO3, EC, SOIL, and SOA and the output species include SO4, NO3, HNO3, EC, SOIL, and SOA. Key POSTUTIL parameters are shown in Figure 19.

```
      Number of species to process from CALPUFF runs
                          (NSPECINP) -- No default    ! NSPECINP = 6 !
      Number of species to write to output file
                          (NSPECOUT) -- No default    ! NSPECOUT = 6 !
      Number of species to compute from those modeled
      (must be no greater than NSPECOUT)
                          (NSPECCMP) -- No default    ! NSPECCMP = 0 !
      Recompute the HNO3/NO3 partition for concentrations?
      (MNITRATE)                    Default: 0       ! MNITRATE  =  1  !
The following NSPECINP species will be processed:

 ! ASPECI =            SO4  !         !END!
 ! ASPECI =            NO3  !         !END!
 ! ASPECI =            HNO3 !         !END!
 ! ASPECI =            EC   !         !END!
 ! ASPECI =            SOIL !         !END!
 ! ASPECI =            SOA  !         !END!

The following NSPECOUT species will be written:

 ! ASPECO =            SO4  !         !END!
 ! ASPECO =            NO3  !         !END!
 ! ASPECO =            HNO3 !         !END!
 ! ASPECO =            EC   !         !END!
 ! ASPECO =            SOIL !         !END!
 ! ASPECO =            SOA  !         !END!
```

Figure 21. POSTUTIL setup for simulations where ammonia limiting is performed using the output file generated from the POSTUTIL setup in Figure 20 (example#2 setup).

5.1.3.3. 98th Percentile Methods

According the BART guideline:

...you should compare your "contribution" threshold against the 98th percentile of values. If the 98th percentile value from your modeling is less than your contribution threshold, then you may conclude that the source does not contribute to visibility impairment and is not subject to BART. (70 FR 39162)

The BART guideline does not contain a specific method for calculating the "98th percentile value" and CALPOST version 5.51 does not generate a 98th percentile delta-deciview value. Consequently, the Division developed a FORTRAN program (BART98_v3) to compute 98th percentile results. The program implements several methods because, at the time the code was written, U.S. EPA had not yet specified an explicit method for determining the 98th percentile value.

The U.S.EPA recommends using the 98th percentile value from the distribution of values containing the highest modeled delta-deciview value for each day of the simulation from all modeled receptors at a given Class I area. The 98th percentile delta-deciview value can be determined in several ways:

- The 8th highest value for each year modeled
- The 3-year average of the annual 8th high values
- The 22nd highest value for the 3-year modeling period

The highest value from the methods above is compared to the contribution threshold. The contribution threshold has an implied level of precision equal to the level of precision reported from CALPOST. Specifically, the 98th percentile results are reported to three decimal places.

The Division's processor BART98_v3 calculates the 98th percentile value with the method recommended by U.S. EPA. The Division refers to the method as the "day-specific method" or "method 1." The first step in the method is to find the highest modeled delta-deciview value for each day of the simulation from all modeled receptors for the selected time period. While this set of delta-deciview values is generated by CALPOST in an unranked format, the Division's processor BART98_v3 outputs all daily delta-deciview values for each receptor from CALPOST and finds the highest impact for each day. Next, the processor ranks the daily delta-deciview maxima in descending order for the number of days processed in CALPOST. Then, the processor determines the 98th percentile value from the distribution of ranked modeled daily maximum values, irrespective of receptor location. For example, for a 365-day simulation, the 98th percentile value would be the 8th highest modeled delta-deciview value from the list of ranked delta-deciview values. That is, the top 7 days are ignored, even though the values being ignored may be at different receptors. Similarly, for a 3-year period, the 98th percentile would be the 22nd highest modeled delta-deciview value.

The processor BART98_v3 also generates 98th percentile values using the "receptor-specific method" or "method 2." This method, which calculates 98th percentile values on a receptor-by-receptor basis, is not used for the subject-to-BART modeling in Colorado.

In order to make the processor more general and to handle missing data, the "8th high" (for one year) and "22nd high" (for 3 years) values recommended by U.S. EPA are not hardwired into the processor; rather, the processor contains an algorithm that calculates the appropriate "nth high" value from the distribution of data. The 8th high and 22nd high values recommended by U.S. EPA are consistent with the values that would be generated from the equations in 40 CFR 50 Appendix N - "Interpretation of the National Ambient Air Quality Standards for PM2.5" – for determining 98th percentile values for PM2.5 monitoring. Thus, the Appendix N method is used in the processor. For the exact algorithm, see Appendix N, the BART98_v3 source code, or the BART98_v3 "readme" file.

6. Results

The CALPUFF modeling results include eleven of the twelve Class I areas in Colorado. Mesa Verde was excluded because it is more than 300 km from all of the BART-eligible sources in Colorado. In addition, the BART-eligible sources in Colorado would have higher impacts at other Class I areas. That is, impacts at Mesa Verde would not be the controlling 98th percentile values for this analysis. The modeling domain does not include Class I areas in any nearby states because the maximum 98th percentile impact from the Craig Station is expected to occur at a Class I area in Colorado.

The results for source-to-receptor distances beyond 300 kilometers may be used, but they may overestimate impacts because puff splitting has not been used. The model setup used here should provide reasonable estimates for source-to-receptor distances up to 300 kilometers. Figure 22 shows the 50km and 300 km radius circles around the modeled BART-eligible source.

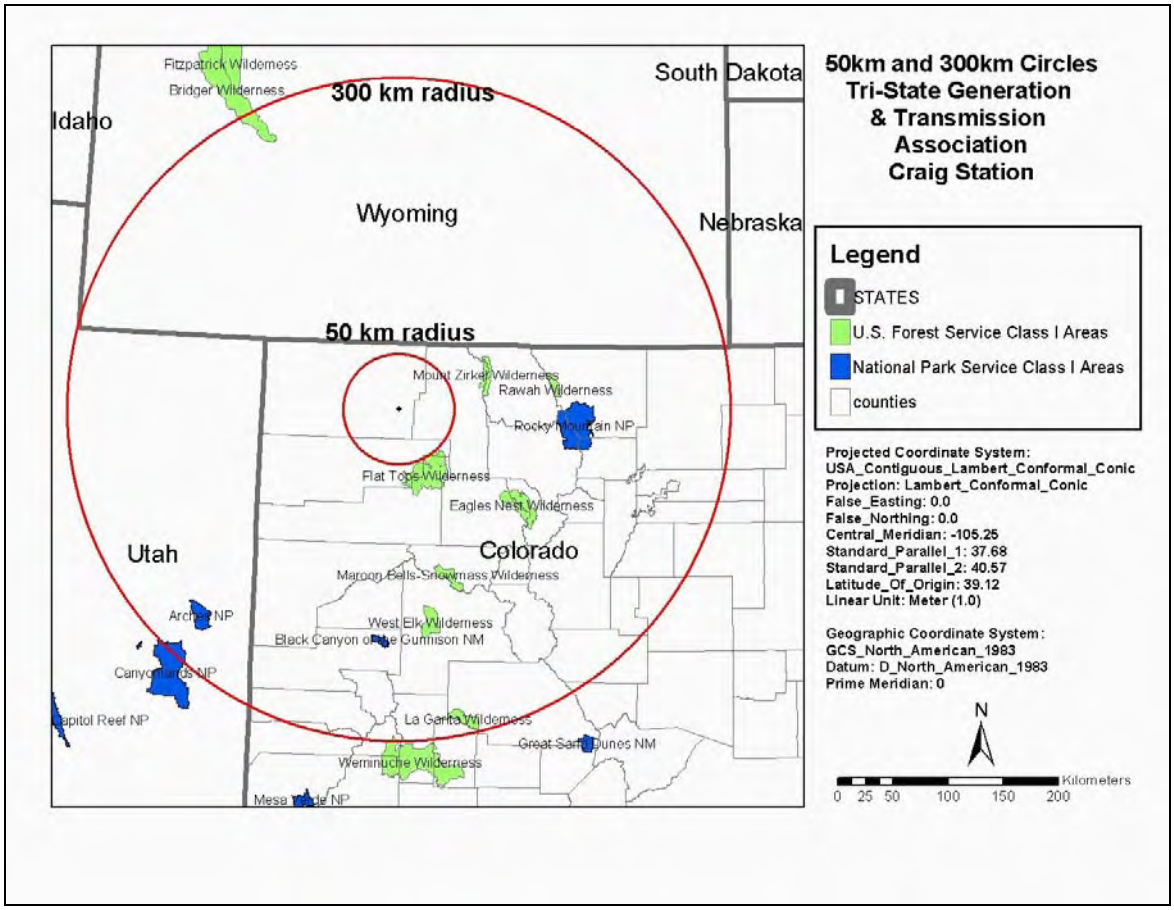

Figure 22. Class I areas within 50 and 300 kilometers of the BART-eligible source.

6.1. Results

The Division has applied the CALPUFF modeling system with three years of meteorological data to determine if the 98th percentile 24-hour change in visibility (delta-deciview) from a BART-eligible source is greater than a contribution threshold of 0.5 deciviews at any Class I area. This initial phase of the BART modeling process is referred to as the "subject to BART" analysis. The modeling includes SO_2, NOx, and direct PM10 emissions from all BART-eligible units at a given facility.

While the modeling results in this report may be used to support regulatory decision making, additional modeling performed by the Division or source operator may supersede the results in this report. If additional modeling is performed, it should be consistent with recommendations in the Division's modeling protocol. Any subsequent modeling performed by the source operator will be subject to Division review and approval. Moreover, the contribution threshold and other criteria used for this modeling demonstration have not been finalized and may change in the final rule adopted by the Commission. Therefore, the results in this report are not a final agency action. Any source that the Division determines is subject to BART will receive a separate notice of the agency's final determination. Such separate notice will occur after the Commission acts on the proposed regulations establishing criteria and procedures for determining which sources will be subject to the BART requirement.

Table 2 and Figure 23 show the 98th percentile daily delta-deciview values for each Class I area in the modeling domain. The 98th percentile delta-deciview value is determined several ways:

- The 8th highest value for each year modeled
- The 3-year average of the annual 8th high values
- The 22nd highest value for the 3-year modeling period

The highest value from the methods above is compared to the contribution threshold. The contribution threshold has an implied level of precision equal to the level of precision reported from CALPOST. Specifically, the 98th percentile results are reported to three decimal places.

The maximum 98th percentile delta-deciview value from Craig Station Units 1 and 2 at any Class I federal area is 2.689 deciviews, assuming natural background conditions and monthly f(RH) values. The impact is above the contribution threshold of 0.5 deciviews. The maximum impact occurs at the Mount Zirkel Wilderness Area. For the three-year period modeled, there are 496 days with an estimated impact over the contribution threshold of 0.5 deciviews.

Table 3 shows the summary report generated by the Division's 98th percentile postprocessor (BART98_v3) for the maximum 98th percentile value. Figure 24 and Figure 25 show the distribution of delta-deciview values used to generate the maximum 98th percentile value. Figure 24 shows the top 25 delta-deciview values at the Class I federal area with the maximum impact from this BART-eligible source.

Table 2. Maximum 98th percentile value, 98th percentile values calculated with several methods, and the number of days the impact is equal to or greater than 0.5 deciviews for the entire period modeled.

CALPUFF Individual Source Attribution Analysis					**Maximum 98th Percentile Value =**	**2.689**
BART-eligible source name:	Craig Station - Units 1 & 2					
	98th Percentile Daily Change in Visibility from BART-Eligible Source Compared Against Natural Background Conditions					
	8th High Delta-Deciview Value					
Class I federal area	**1996[1]**	**2001**	**2002**	**3-year Average**	**22nd High Delta-Deciview Value from 3-year Modeling Period**	**Number of Days Impact >0.5dv (1996, 2001, 2002)**
Flat Tops WA	2.093	1.615	2.095	1.934	1.996	168
Rawah WA	1.587	1.393	1.929	1.636	1.588	190
Mt Zirkel WA	2.131	2.226	2.689	2.349	2.315	496
Weminuche WA	0.172	0.097	0.194	0.154	0.165	4
Rocky Mountain NP	1.753	1.267	1.935	1.652	1.765	205
Maroon Bells-Snowmass WA	0.983	0.621	0.563	0.722	0.652	37
La Garita WA	0.279	0.154	0.234	0.222	0.205	3
Great Sand Dunes NP	0.468	0.323	0.360	0.384	0.403	11
West Elk WA	0.566	0.505	0.433	0.501	0.515	26
Eagles Nest WA	1.560	1.106	1.211	1.292	1.260	109
Black Canyon of the Gunnison NP	0.467	0.265	0.338	0.357	0.382	17

[1] *1996, 2001, and 2002 are the years of meteorological data modeled.*

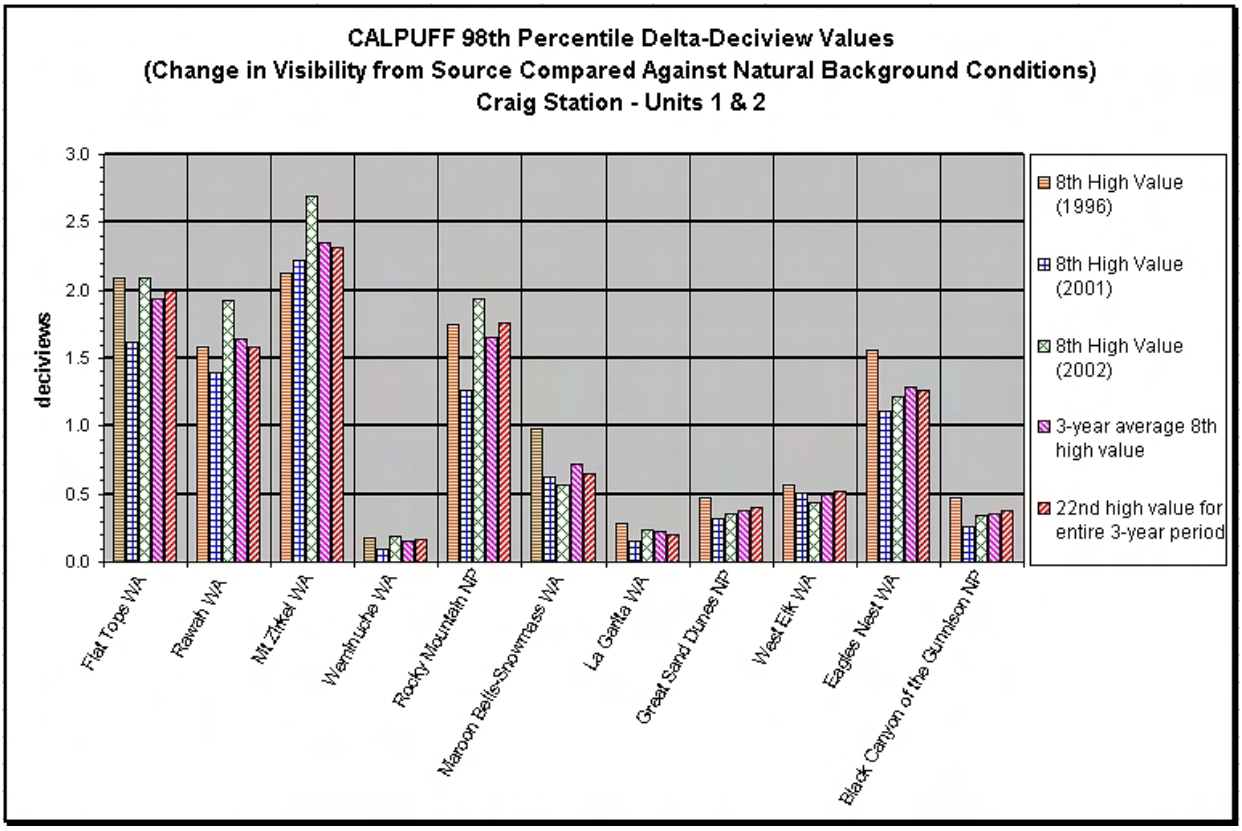

Figure 23. Comparison of 98th percentile daily change in visibility values (delta-deciviews). The highest value is compared to the contribution threshold of 0.5 deciviews.

Table 3. Summary report with results from the Division's 98th percentile postprocessor (BART98_v3) that correspond to the maximum delta-deciview value from Table 2. The 98th percentile value from "Method 1" (in bold) corresponds to the method recommended by U.S. EPA.

```
Title from CALPOST:
APCD BART - Mt Zirkel WA (MOZ); 2/22/06 v1_so2at0.16NOxat0.34_mnitrate1ppb
MVISBK=6; EPA2003 centroid monthly f(RH); EPA2003 20%bestdays natural backgrd
2002 36km MM5, 4km CALMET, hourly ozone; BART-eligible source= CRAIG

Days processed:  364
Receptors processed:      253
CALPOST species: ALL
Contribution threshold: 0.5

Summary of delta-deciview results:

The 'High  1st High' from the model is:   3.489 dv
    Number of days 'High 1 High' delta-deciview => 0.5: 199
    Number of days 'High 1 High' delta-deciview => 1.00:  96


98th Percentile Results:
-------------------------------------------------------------
Method 1. DAY-SPECIFIC - closest modeled value:
    The ' 8 High' value from the model is:  2.689 dv
       at receptor    3021 on day  118(2002)

Method 2a. RECEPTOR-SPECIFIC - closest modeled value:
    The 'High  8 High' value from the model is:  2.041 dv
       at receptor    2868 on day  325(2002)
    Number of days with delta-deciview => 0.5: 198
    Number of days with delta-deciview => 1.00:  95

Method 2b. RECEPTOR-SPECIFIC - Weighted Average at X[(n+1)p]:
    The calculated 98th percentile value
    using a weighted averaging method is:    2.050 dv
       at receptor    2868
       using days   12(2002) and 325(2002)
-------------------------------------------------------------
```

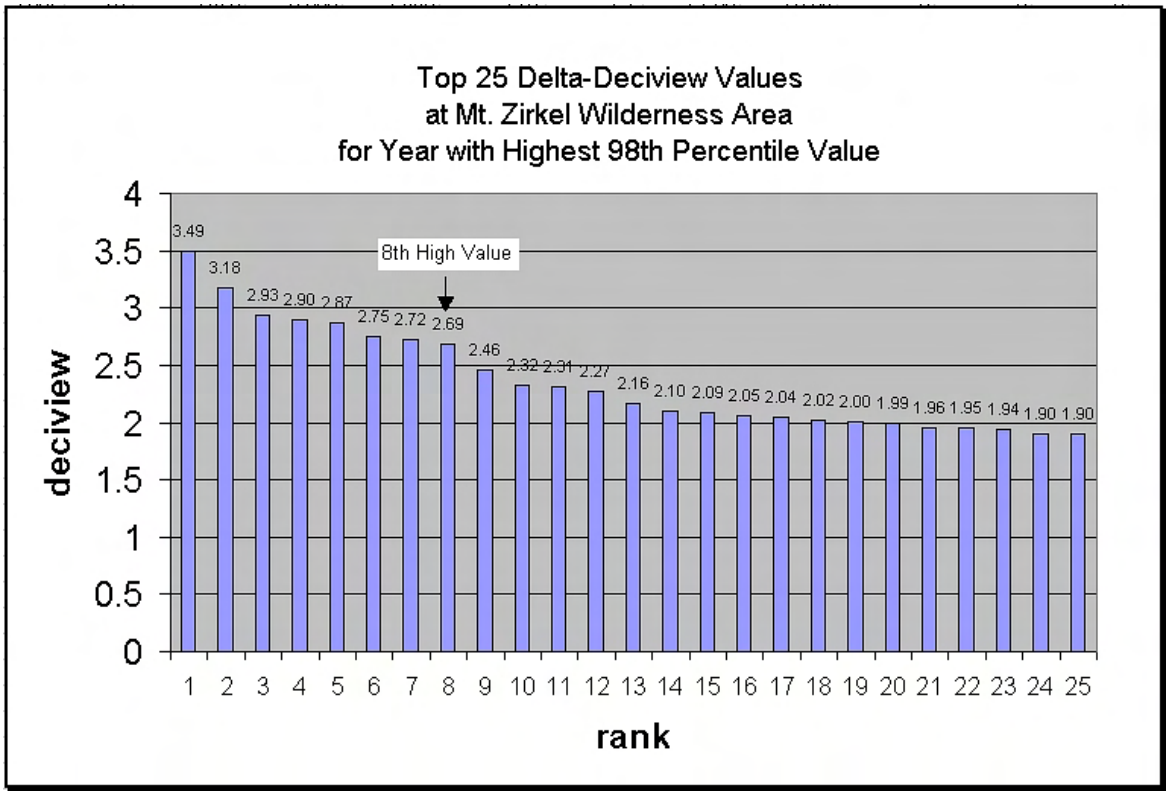

Figure 24. Distribution of delta-deciview values used to generate the maximum 98th percentile value.

YEAR	DAY	RECEPTOR	DV(Total)	DV(BKG)	DELTA DV	F(RH)	%_SO4	%_NO3	%_OC	%_EC	%_PMC	%_PMF
2002	359	2948	5.463	1.974	3.489	2.1	13.11	85.07	0	0	0	1.82
2002	38	2880	5.175	1.996	3.179	2.2	14.75	84.68	0	0	0	0.57
2002	335	3075	4.907	1.974	2.932	2.1	9.33	89.78	0	0	0	0.89
2002	34	3075	4.894	1.996	2.898	2.2	14.56	84.88	0	0	0	0.56
2002	332	2880	4.84	1.974	2.866	2.1	11.01	86.83	0	0	0	2.16
2002	30	2855	4.749	1.996	2.753	2.2	10.62	85.03	0	0	0	4.34
2002	293	2949	4.653	1.93	2.723	1.9	20.07	79.15	0	0	0	0.77
2002	118	3021	4.663	1.974	**2.689**	2.1	11.02	84.89	0	0	0	4.08
2002	145	2852	4.457	1.996	2.461	2.2	13.94	83.72	0	0	0	2.34
2002	124	2855	4.32	1.996	2.324	2.2	7.85	87.48	0	0	0	4.67
2002	344	3011	4.285	1.974	2.311	2.1	9.64	89.05	0	0	0	1.31
2002	360	2868	4.242	1.974	2.268	2.1	8.63	87.81	0	0	0	3.56
2002	298	3075	4.092	1.93	2.162	1.9	10.59	86.24	0	0	0	3.17
2002	341	3075	4.075	1.974	2.101	2.1	9.22	89.47	0	0	0	1.31
2002	84	3075	4.042	1.952	2.09	2	11.32	86.58	0	0	0	2.1
2002	12	2868	4.05	1.996	2.054	2.2	11.58	87.69	0	0	0	0.73
2002	325	2868	4.016	1.974	2.041	2.1	10.67	87.59	0	0	0	1.73
2002	137	2855	4.013	1.996	2.017	2.2	11.59	86.75	0	0	0	1.66
2002	326	2915	3.976	1.974	2.002	2.1	9.79	89.47	0	0	0	0.74
2002	255	3011	3.94	1.952	1.988	2	9.08	87.74	0	0	0	3.18
2002	85	2852	3.91	1.952	1.958	2	12.86	84.85	0	0	0	2.28
2002	292	2855	3.878	1.93	1.948	1.9	20.83	77.8	0	0	0	1.37
2002	51	2852	3.94	1.996	1.944	2.2	5.78	89.7	0	0	0	4.52
2002	297	3032	3.832	1.93	1.901	1.9	12.23	83.26	0	0	0	4.51
2002	302	2915	3.83	1.93	1.9	1.9	10.98	85.65	0	0	0	3.36

Figure 25. Top 25 delta-deciview (DELTA DV) values from the Mt Zirkel Wilderness Area for the year with the highest 98th percentile value.

7. References

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Appendix A – Natural Background Values

Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [a]	Worst Days (dv) [a]
Acadia NP	ME	44.35	-68.24	21.40	7.61	3.77	11.45
Agua Tibia Wilderness	CA	33.42	-116.99	15.86	4.61	2.05	7.17
Alpine Lake Wilderness	WA	47.55	-121.16	16.99	5.30	2.74	7.86
Anaconda-Pintler Wilderness	MT	45.95	-113.5	16.03	4.72	2.16	7.28
Arches NP	UT	38.73	-109.58	15.58	4.43	1.87	6.99
Badlands NP	SD	43.81	-102.36	16.06	4.74	2.18	7.30
Bandelier NM	NM	35.79	-106.34	15.62	4.46	1.90	7.02
Bering Sea	AK	60.46	-172.75				
Big Bend NP	TX	29.33	-103.31	15.48	4.37	1.81	6.93
Black Canyon of the Gunnison NM	CO	38.57	-107.75	15.68	4.50	1.94	7.06
Bob Marshall Wilderness	MT	47.68	-113.23	16.17	4.80	2.24	7.36
Bosque del Apache	NM	33.79	-106.85	15.54	4.41	1.85	6.97
Boundary Waters Canoe Area	MN	48.06	-91.43	20.89	7.37	3.53	11.21
Breton	LA	29.87	-88.82	21.57	7.69	3.85	11.53
Bridger Wilderness	WY	42.99	-109.49	15.71	4.52	1.96	7.08
Brigantine	NJ	39.49	-74.39	21.05	7.44	3.60	11.28
Bryce Canyon NP	UT	37.57	-112.17	15.58	4.43	1.87	6.99
Cabinet Mountains Wilderness	MT	48.18	-115.68	16.27	4.87	2.31	7.43
Caney Creek Wilderness	AR	34.41	-94.08	21.14	7.49	3.65	11.33
Canyonlands NP	UT	38.23	-109.91	15.60	4.45	1.89	7.01
Cape Romain	SC	32.99	-79.49	21.22	7.52	3.68	11.36
Capitol Reef NP	UT	38.06	-111.15	15.63	4.47	1.91	7.03
Caribou Wilderness	CA	40.49	-121.21	16.05	4.73	2.17	7.29
Carlsbad Caverns NP	NM	32.12	-104.59	15.61	4.46	1.90	7.02
Chassahowitzka	FL	28.69	-82.66	21.46	7.63	3.79	11.47
Chiricahua NM	AZ	32.01	-109.34	15.47	4.36	1.80	6.92
Chiricahua Wilderness	AZ	31.86	-109.28	15.45	4.35	1.79	6.91
Cohutta Wilderness	GA	34.93	-84.57	21.39	7.60	3.76	11.44
Crater Lake NP	OR	42.92	-122.13	16.74	5.15	2.59	7.71
Craters of the Moon NM	ID	43.39	-113.54	15.80	4.57	2.01	7.13
Cucamonga Wilderness	CA	34.24	-117.59	15.85	4.61	2.05	7.17
Denali Preserve NP	AK	63.31	-151.19	16.27	4.86	2.30	7.42
Desolation Wilderness	CA	38.9	-120.17	15.80	4.57	2.01	7.13
Diamond Peak Wilderness	OR	43.53	-122.1	16.84	5.21	2.65	7.77
Dolly Sods Wilderness	WV	39	-79.37	21.13	7.48	3.64	11.32
Dome Land Wilderness	CA	35.84	-118.23	15.70	4.51	1.95	7.07
Eagle Cap Wilderness	OR	45.22	-117.37	16.12	4.78	2.22	7.34

Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [a]	Worst Days (dv) [a]
Eagles Nest Wilderness	CO	39.67	-106.29	15.72	4.52	1.96	7.08
Emigrant Wilderness	CA	38.18	-119.77	15.81	4.58	2.02	7.14
Everglades NP	FL	25.35	-80.98	20.77	7.31	3.47	11.15
Fitzpatrick Wilderness	WY	43.24	-109.6	15.73	4.53	1.97	7.09
Flat Tops Wilderness	CO	39.95	-107.3	15.70	4.51	1.95	7.07
Galiuro Wilderness	AZ	32.6	-110.39	15.40	4.32	1.76	6.88
Gates of the Mountains Wilderness	MT	46.86	-111.82	15.93	4.66	2.10	7.22
Gearhart Mountain Wilderness	OR	42.51	-120.86	16.33	4.90	2.34	7.46
Gila Wilderness	NM	33.21	-108.47	15.51	4.39	1.83	6.95
Glacier NP	MT	48.64	-113.84	16.48	5.00	2.44	7.56
Glacier Peak Wilderness	WA	48.21	-121	16.88	5.24	2.68	7.80
Goat Rocks Wilderness	WA	46.52	-121.47	16.93	5.26	2.70	7.82
Grand Canyon NP	AZ	36.3	-112.79	15.51	4.39	1.83	6.95
Grand Teton NP	WY	43.82	-110.71	15.74	4.53	1.97	7.09
Great Gulf Wilderness	NH	44.3	-71.28	21.10	7.47	3.63	11.31
Great Sand Dunes NM	CO	37.77	-105.57	15.74	4.54	1.98	7.10
Great Smoky Mountains NP	TN	35.6	-83.52	21.39	7.60	3.76	11.44
Guadalupe Mountains NP	TX	31.91	-104.85	15.64	4.47	1.91	7.03
Haleakala NP	HI	20.71	-156.16	16.02	4.71	2.15	7.27
Hawaii Volcanoes NP	HI	19.41	-155.34	16.33	4.91	2.35	7.47
Hells Canyon Wilderness	OR	45.54	-116.59	16.09	4.76	2.20	7.32
Hercules-Glades Wilderness	MO	36.68	-92.9	21.03	7.43	3.59	11.27
Hoover Wilderness	CA	38.11	-119.37	15.78	4.56	2.00	7.12
Isle Royale NP	MI	48.01	-88.83	20.91	7.38	3.54	11.22
James River Face Wilderness	VA	37.59	-79.44	20.96	7.40	3.56	11.24
Jarbidge Wilderness	NV	41.77	-115.35	15.75	4.54	1.98	7.10
John Muir Wilderness	CA	36.97	-118.88	15.80	4.58	2.02	7.14
Joshua Tree NM	CA	33.92	-115.88	15.72	4.52	1.96	7.08
Joyce-Kilmer-Slickrock Wilderness	TN	35.44	-83.99	21.40	7.61	3.77	11.45
Kaiser Wilderness	CA	37.28	-119.17	15.80	4.57	2.01	7.13
Kalmiopsis Wilderness	OR	42.26	-123.92	16.74	5.15	2.59	7.71
Kings Canyon NP	CA	36.92	-118.61	15.79	4.57	2.01	7.13
La Garita Wilderness	CO	37.95	-106.83	15.69	4.50	1.94	7.06
Lassen Volcanic NP	CA	40.49	-121.41	16.08	4.75	2.19	7.31
Lava Beds NM	CA	41.76	-121.52	16.37	4.93	2.37	7.49
Linville Gorge Wilderness	NC	35.88	-81.9	21.36	7.59	3.75	11.43
Lostwood	ND	48.59	-102.46	16.11	4.77	2.21	7.33

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Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [a]	Worst Days (dv) [a]
Lye Brook Wilderness	VT	43.13	-73.02	20.99	7.41	3.57	11.25
Mammoth Cave NP	KY	37.2	-86.15	21.58	7.69	3.85	11.53
Marble Mountain Wilderness	CA	41.51	-123.21	16.65	5.10	2.54	7.66
Maroon Bells-Snowmass Wilderness	CO	39.1	-107.02	15.70	4.51	1.95	7.07
Mazatzal Wilderness	AZ	34.13	-111.56	15.44	4.35	1.79	6.91
Medicine Lake	MT	48.49	-104.35	16.07	4.74	2.18	7.30
Mesa Verde NP	CO	37.25	-108.45	15.73	4.53	1.97	7.09
Minarets Wilderness	CA	37.74	-119.19	15.78	4.56	2.00	7.12
Mingo	MO	37	-90.19	21.03	7.43	3.59	11.27
Mission Mountains Wilderness	MT	47.48	-113.87	16.21	4.83	2.27	7.39
Mokelumne Wilderness	CA	38.57	-120.06	15.80	4.58	2.02	7.14
Moosehorn	ME	45.09	-67.29	21.22	7.52	3.68	11.36
Mount Adams Wilderness	WA	46.2	-121.49	16.86	5.22	2.66	7.78
Mount Baldy Wilderness	AZ	33.95	-109.54	15.51	4.39	1.83	6.95
Mount Hood Wilderness	OR	45.37	-121.73	16.83	5.21	2.65	7.77
Mount Jefferson Wilderness	OR	44.61	-121.84	16.91	5.25	2.69	7.81
Mount Rainier NP	WA	46.86	-121.72	17.05	5.34	2.78	7.90
Mount Washington Wilderness	OR	44.3	-121.88	17.03	5.33	2.77	7.89
Mount Zirkel Wilderness	CO	40.75	-106.68	15.71	4.52	1.96	7.08
Mountain Lakes Wilderness	OR	42.33	-122.11	16.50	5.01	2.45	7.57
North Absaroka Wilderness	WY	44.74	-109.8	15.74	4.53	1.97	7.09
North Cascades NP	WA	48.83	-121.35	16.86	5.22	2.66	7.78
Okefenokee	GA	30.82	-82.33	21.41	7.61	3.77	11.45
Olympic NP	WA	47.77	-123.74	17.02	5.32	2.76	7.88
Otter Creek Wilderness	WV	38.99	-79.65	21.14	7.49	3.65	11.33
Pasayten Wilderness	WA	48.89	-120.44	16.84	5.21	2.65	7.77
Pecos Wilderness	NM	35.9	-105.62	15.65	4.48	1.92	7.04
Petrified Forest NP	AZ	34.99	-109.79	15.54	4.41	1.85	6.97
Pine Mountain Wilderness	AZ	34.31	-111.8	15.47	4.36	1.80	6.92
Pinnacles NM	CA	36.48	-121.19	16.12	4.78	2.22	7.34
Point Reyes NS	CA	38.06	-122.9	16.20	4.83	2.27	7.39
Presidential Range-Dry River Wilderness	NH	44.2	-71.34	21.15	7.49	3.65	11.33
Rainbow Lake Wilderness	WI	46.42	-91.31	20.99	7.42	3.58	11.26
Rawah Wilderness	CO	40.69	-105.95	15.72	4.52	1.96	7.08
Red Rock Lakes	MT	44.64	-111.78	15.81	4.58	2.02	7.14
Redwood NP	CA	41.44	-124.03	16.90	5.25	2.69	7.81
Rocky Mountain NP	CO	40.35	-105.7	15.67	4.49	1.93	7.05

Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [a]	Worst Days (dv) [a]
Roosevelt Campobello International Park	ME	44.85	-66.94	21.22	7.52	3.68	11.36
Saguaro NM	AZ	32.17	-110.61	15.35	4.28	1.72	6.84
Salt Creek	NM	33.6	-104.41	15.58	4.43	1.87	6.99
San Gabriel Wilderness	CA	34.27	-117.94	15.86	4.61	2.05	7.17
San Gorgonio Wilderness	CA	34.12	-116.84	15.74	4.54	1.98	7.10
San Jacinto Wilderness	CA	33.75	-116.64	15.78	4.56	2.00	7.12
San Pedro Parks Wilderness	NM	36.11	-106.81	15.63	4.47	1.91	7.03
San Rafael Wilderness	CA	34.76	-119.81	16.03	4.72	2.16	7.28
Sawtooth Wilderness	ID	43.99	-115.06	15.82	4.59	2.03	7.15
Scapegoat Wilderness	MT	47.16	-112.74	16.05	4.73	2.17	7.29
Selway-Bitterroot Wilderness	ID	46.12	-114.86	16.09	4.76	2.20	7.32
Seney	MI	46.25	-86.09	21.23	7.53	3.69	11.37
Sequoia NP	CA	36.51	-118.56	15.79	4.57	2.01	7.13
Shenandoah NP	VA	38.47	-78.49	20.98	7.41	3.57	11.25
Shining Rock Wilderness	NC	35.38	-82.85	21.40	7.61	3.77	11.45
Sierra Ancha Wilderness	AZ	33.85	-110.9	15.46	4.36	1.80	6.92
Simeonof	AK	54.91	-159.28	17.21	5.43	2.87	7.99
Sipsey Wilderness	AL	34.32	-87.44	21.28	7.55	3.71	11.39
South Warner Wilderness	CA	41.31	-120.2	16.09	4.76	2.20	7.32
St. Marks	FL	30.11	-84.15	21.54	7.67	3.83	11.51
Strawberry Mountain Wilderness	OR	44.29	-118.74	16.37	4.93	2.37	7.49
Superstition Wilderness	AZ	33.5	-111.27	15.40	4.32	1.76	6.88
Swanquarter	NC	35.39	-76.39	20.91	7.38	3.54	11.22
Sycamore Canyon Wilderness	AZ	35.01	-112.09	15.53	4.40	1.84	6.96
Teton Wilderness	WY	44.04	-110.17	15.74	4.53	1.97	7.09
Theodore Roosevelt NP	ND	46.96	-103.46	16.08	4.75	2.19	7.31
Thousand Lakes Wilderness	CA	40.7	-121.58	16.10	4.76	2.20	7.32
Three Sisters Wilderness	OR	44.04	-121.91	17.01	5.31	2.75	7.87
Tuxedni	AK	60.14	-152.61	16.58	5.06	2.50	7.62
UL Bend	MT	47.54	-107.89	15.87	4.62	2.06	7.18
Upper Buffalo Wilderness	AR	36.17	-92.41	21.04	7.44	3.60	11.28
Ventana Wilderness	CA	36.21	-121.6	16.09	4.76	2.20	7.32
Virgin Islands NP [b]	VI	18.35	-64.74				
Voyageurs NP	MN	48.47	-92.8	20.64	7.25	3.41	11.09
Washakie Wilderness	WY	44.1	-109.57	15.73	4.53	1.97	7.09
Weminuche Wilderness	CO	37.61	-107.25	15.68	4.50	1.94	7.06
West Elk Wilderness	CO	38.75	-107.21	15.71	4.51	1.95	7.07

Appendix B
Default Natural b_{ext}, *dv*, and 10th and 90th Percentile *dv* Values at All Mandatory Federal Class I Areas

Mandatory Federal Class I Area	State	Lat.	Lon.	bext (Mm-1)	Ann. Avg. (dv)	Best Days (dv) [a]	Worst Days (dv) [a]
Wheeler Peak Wilderness	NM	36.57	-105.4	15.70	4.51	1.95	7.07
White Mountain Wilderness	NM	33.48	-105.85	15.56	4.42	1.86	6.98
Wichita Mountains	OK	34.75	-98.65	20.60	7.23	3.39	11.07
Wind Cave NP	SD	43.58	-103.47	15.97	4.68	2.12	7.24
Wolf Island	GA	31.33	-81.3	21.33	7.58	3.74	11.42
Yellowstone NP	WY	44.63	-110.51	15.77	4.56	2.00	7.12
Yolla Bolly Middle Eel Wilderness	CA	40.09	-122.96	16.25	4.85	2.29	7.41
Yosemite NP	CA	37.85	-119.54	15.81	4.58	2.02	7.14
Zion NP	UT	37.32	-113.04	15.56	4.42	1.86	6.98

(a) Values for the best and worst days are estimated from a statistical approach described in Section 2.6 of this document.
(b) *f(RH)* values for Virgin Islands National Park were not calculated because of the limited RH data available. As such no estimates for Natural Visibility Conditions are presented at this time.

Appendix B – Monthly f(RH) Values

Guidance for Tracking Progress Under the Regional Haze Rule

Table A-3 Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Centroid of the Area (Supplemental Information)

Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Acadia	Acadia	1	ACAD1	ME	44.37	68.26	3.3	2.9	2.8	3.4	3.1	3.0	3.4	3.8	4.0	3.8	3.6	3.5
Agua Tibia	Agua Tibia	100	AGTI1	CA	33.41	116.98	2.4	2.4	2.4	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.1	2.2
Alpine Lakes	Snoqualmie Pass	80	SNPA1	WA	47.42	121.42	4.3	3.8	3.5	3.9	2.9	3.2	2.9	3.1	3.3	3.9	4.5	4.5
Anaconda - Pintler	Sula	71	SULA1	MT	45.98	113.42	3.3	2.9	2.5	2.4	2.4	2.3	2.0	1.9	2.1	2.5	3.2	3.3
Ansel Adams	Kaiser	110	KAIS1	CA	37.65	119.20	3.0	2.7	2.4	2.1	1.9	1.7	1.6	1.6	1.6	1.8	2.3	2.7
Arches	Canyonlands	50	CANY1	UT	38.64	109.58	2.6	2.3	1.8	1.6	1.6	1.3	1.4	1.5	1.6	1.6	2.0	2.3
Badlands	Badlands	59	BADL1	SD	43.74	101.94	2.6	2.7	2.6	2.4	2.8	2.7	2.5	2.4	2.2	2.3	2.7	2.7
Bandelier	Bandelier	33	BAND1	NM	35.78	106.27	2.2	2.1	1.8	1.6	1.6	1.4	1.7	2.1	1.9	1.7	2.0	2.2
Bering Sea (a)					60.45	172.79												
Big Bend	Big Bend	31	BIBE1	TX	29.31	103.19	2.0	1.9	1.6	1.5	1.6	1.6	1.7	2.0	2.1	1.9	1.8	1.9
Black Canyon of the Gunnison	Weminuche	55	WEMI1	CO	38.58	107.70	2.4	2.2	1.9	1.9	1.9	1.6	1.7	1.9	2.0	1.8	2.1	2.3
Bob Marshall	Monture	73	MONT1	MT	47.75	113.38	3.6	3.1	2.8	2.6	2.7	2.7	2.3	2.2	2.6	2.9	3.5	3.5
Bosque del Apache	Bosque del Apache	38	BOAP1	NM	33.79	106.83	2.1	1.9	1.6	1.4	1.4	1.3	1.8	2.0	1.9	1.6	1.8	2.2
Boundary Waters Canoe Area	Boundary Waters	23	BOWA1	MN	47.95	91.50	3.0	2.6	2.7	2.4	2.3	2.9	3.1	3.4	3.5	2.8	3.2	3.2
Breton	Breton	20	BRET1	LA	29.73	88.88	3.7	3.5	3.7	3.6	3.8	4.0	4.3	4.3	4.2	3.7	3.7	3.7
Bridger	Bridger	65	BRID1	WY	42.98	109.76	2.5	2.4	2.3	2.2	2.1	1.8	1.5	1.5	1.7	2.0	2.4	2.4
Brigantine	Brigantine	5	BRIG1	NJ	39.46	74.45	2.8	2.6	2.7	2.6	3.0	3.2	3.4	3.7	3.6	3.3	2.9	2.8
Bryce Canyon	Bryce Canyon	49	BRCA1	UT	37.62	112.17	2.6	2.4	1.9	1.6	1.5	1.3	1.3	1.5	1.5	1.6	2.0	2.4
Cabinet Mountains	Cabinet Mountains	75	CABI1	MT	48.21	115.71	3.8	3.3	2.9	2.6	2.7	2.7	2.3	2.2	2.6	3.0	3.7	3.9
Caney Creek	Caney Creek	29	CACR1	AR	34.41	94.08	3.4	3.1	2.9	3.0	3.6	3.6	3.4	3.4	3.6	3.5	3.4	3.5
Canyonlands	Canyonlands	50	CANY1	UT	38.46	109.82	2.6	2.3	1.7	1.6	1.5	1.2	1.3	1.5	1.6	1.6	2.0	2.3
Cape Romain	Cape Romain	15	ROMA1	SC	32.94	79.66	3.3	3.0	2.9	2.8	3.2	3.7	3.6	4.1	4.0	3.7	3.4	3.2
Capitol Reef	Capitol Reef	52	CAPI1	UT	38.36	111.05	2.7	2.4	2.0	1.7	1.6	1.4	1.4	1.6	1.6	1.7	2.1	2.5
Caribou	Lassen Volcanic	90	LAVO1	CA	40.50	121.18	3.7	3.1	2.8	2.5	2.4	2.2	2.1	2.1	2.2	2.4	3.0	3.4
Carlsbad Caverns	Guadalupe Mountains	32	GUMO1	TX	32.14	104.48	2.1	2.0	1.6	1.5	1.6	1.6	1.8	2.1	2.2	1.8	1.9	2.1
Chassahowitzka	Chassahowitzka	18	CHAS1	FL	28.75	82.55	3.8	3.5	3.4	3.2	3.3	3.9	3.9	4.2	4.1	3.9	3.7	3.9
Chiricahua NM	Chiricahua	39	CHIR1	AZ	32.01	109.39	2.0	2.0	1.6	1.3	1.3	1.1	1.8	2.1	1.8	1.5	1.6	2.2
Chiricahua W	Chiricahua	39	CHIR1	AZ	31.84	109.27	2.0	1.9	1.6	1.2	1.3	1.1	1.8	2.1	1.8	1.5	1.6	2.2
Cohutta	Cohutta	12	COHU1	GA	34.92	84.58	3.3	3.1	3.0	2.8	3.4	3.8	4.0	4.2	4.2	3.8	3.4	3.5
Crater Lake	Crater Lake	86	CRLA1	OR	42.90	122.13	4.6	3.9	3.7	3.4	3.2	3.0	2.8	2.9	3.1	3.6	4.6	4.6
Craters of the Moon	Craters of the Moon	69	CRMO1	ID	43.47	113.55	3.1	2.7	2.3	2.0	2.0	1.8	1.4	1.4	1.6	2.0	2.8	3.0
Cucamonga	San Gabriel	93	SAGA1	CA	34.25	117.57	2.5	2.4	2.4	2.2	2.1	2.1	2.1	2.2	2.2	2.2	2.1	2.2
Denali	Denali	102	DENA1	AK	63.72	148.97	2.5	2.3	2.1	1.9	1.9	2.2	2.5	3.0	2.8	2.9	3.0	3.1
Desolation	Bliss	95	BLIS1	CA	38.98	120.12	3.2	2.8	2.4	2.0	1.8	1.6	1.5	1.6	1.7	1.9	2.4	3.0
Diamond Peak	Crater Lake	86	CRLA1	OR	43.53	122.10	4.5	4.0	3.6	3.7	3.2	3.1	2.9	2.9	3.1	3.7	4.6	4.6
Dolly Sods	Dolly Sods	8	DOSO1	WV	39.11	79.43	3.0	2.8	2.8	2.6	3.1	3.4	3.5	3.9	3.9	3.3	3.0	3.1

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Guidance for Tracking Progress Under the Regional Haze Rule

Table A-3 Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Centroid of the Area (Supplemental Information)

Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Dome Land	Dome Land	109	DOME1	CA	35.70	118.19	2.5	2.3	2.2	1.9	1.8	1.8	1.8	1.8	1.8	1.9	2.0	2.2
Eagle Cap	Starkey	76	STAR1	OR	45.10	117.29	3.8	3.2	2.5	2.1	2.0	1.9	1.6	1.6	1.6	2.3	3.4	4.0
Eagles Nest	White River	56	WHRI1	CO	39.69	106.25	2.2	2.2	2.0	2.0	2.1	1.9	1.8	2.0	2.0	1.9	2.1	2.1
Emigrant	Yosemite	96	YOSE1	CA	38.20	119.75	3.2	2.8	2.5	2.1	1.9	1.7	1.5	1.6	1.6	1.9	2.4	2.9
Everglades	Everglades	19	EVER1	FL	25.39	80.68	2.7	2.6	2.6	2.4	2.4	2.7	2.6	2.9	3.0	2.8	2.6	2.7
Fitzpatrick	Bridger	65	BRID1	WY	43.27	109.57	2.5	2.3	2.2	2.1	2.1	1.8	1.5	1.5	1.7	2.0	2.4	2.4
Flat Tops	White River	56	WHRI1	CO	39.97	107.25	2.3	2.2	2.0	2.0	2.0	1.8	1.7	1.9	1.9	1.8	2.2	2.2
Galiuro	Chiricahua	39	CHIR1	AZ	32.56	110.32	2.0	1.8	1.5	1.2	1.2	1.1	1.5	1.8	1.6	1.5	1.6	2.1
Gates of the Mountains	Gates of the Mountains	74	GAMO1	MT	46.87	111.81	2.9	2.6	2.4	2.3	2.3	2.3	2.0	1.9	2.1	2.4	2.8	2.8
Gearhart Mountain	Crater Lake	86	CRLA1	OR	42.49	120.85	4.0	3.4	3.1	2.8	2.7	2.5	2.3	2.3	2.4	2.8	3.7	3.8
Gila	Gila Cliffs	42	GICL1	NM	33.22	108.25	2.1	1.9	1.6	1.3	1.4	1.2	2.1	2.0	1.8	1.6	1.8	2.2
Glacier	Glacier	72	GLAC1	MT	48.51	114.00	4.0	3.5	3.2	3.1	3.2	3.4	2.8	2.6	3.2	3.5	3.8	3.9
Glacier Peak	North Cascades	81	NOCA1	WA	48.21	121.04	4.2	3.7	3.4	3.8	2.9	3.2	2.9	3.1	3.3	3.9	4.4	4.4
Goat Rocks	White Pass	79	WHPA1	WA	46.54	121.48	4.3	3.8	3.4	4.2	2.8	3.4	3.0	3.2	3.1	3.8	4.4	4.6
Grand Canyon	Grand Canyon, Hance	48	GRCA2	AZ	35.97	111.98	2.4	2.3	1.9	1.5	1.4	1.2	1.4	1.7	1.6	1.6	1.9	2.3
Grand Teton	Yellowstone	66	YELL2	WY	43.68	110.73	2.6	2.4	2.2	2.1	2.1	1.8	1.5	1.5	1.7	2.0	2.4	2.6
Great Gulf	Great Gulf	4	GRGU1	NH	44.31	71.22	2.8	2.6	2.6	2.8	2.9	3.2	3.5	3.8	4.0	3.4	3.1	2.9
Great Sand Dunes	Great Sand Dunes	53	GRSA1	CO	37.73	105.52	2.4	2.3	2.0	1.9	1.9	1.8	1.9	2.3	2.2	1.9	2.4	2.4
Great Smoky Mountains	Great Smoky Mountains	10	GRSM1	TN	35.63	83.94	3.3	3.0	2.9	2.7	3.2	3.9	3.8	4.0	4.2	3.8	3.3	3.4
Guadalupe Mountains	Guadalupe Mountains	32	GUMO1	TX	31.83	104.80	2.0	2.0	1.6	1.5	1.6	1.5	1.9	2.2	2.2	1.8	1.9	2.2
Haleakala	Haleakala	108	HALE1	HI	20.81	156.28	2.7	2.6	2.6	2.5	2.4	2.3	2.5	2.4	2.4	2.5	2.8	2.7
Hawaii Volcanoes	Hawaii Volcanoes	107	HAVO1	HI	19.43	155.27	3.2	2.9	3.0	3.0	3.0	2.9	3.1	3.2	3.2	3.2	3.7	3.2
Hells Canyon	Hells Canyon	77	HECA1	OR	45.34	116.57	3.7	3.1	2.5	2.2	2.1	2.0	1.6	1.6	1.8	2.4	3.5	3.9
Hercules - Glade	Hercules - Glade	28	HEGL1	MO	36.69	92.90	3.2	2.9	2.7	2.7	3.3	3.3	3.3	3.3	3.4	3.1	3.1	3.3
Hoover	Hoover	97	HOOV1	CA	38.14	119.45	3.1	2.8	2.5	2.1	1.9	1.6	1.5	1.5	1.6	1.8	2.3	2.8
Isle Royale	Isle Royale	25	ISLE1	MI	47.99	88.83	3.1	2.5	2.7	2.4	2.2	2.6	3.0	3.2	3.8	2.7	3.3	3.3
James River Face	James River Face	7	JARI1	VA	37.62	79.48	2.8	2.6	2.7	2.4	3.0	3.3	3.4	3.7	3.6	3.2	2.8	3.0
Jarbidge	Jarbidge	68	JARB1	NV	41.89	115.43	3.0	2.6	2.1	2.1	2.2	2.2	1.6	1.4	1.4	1.6	2.4	2.8
John Muir	Kaiser	110	KAIS1	CA	37.39	118.84	2.9	2.6	2.4	2.1	1.9	1.7	1.7	1.7	1.7	1.9	2.2	2.6
Joshua Tree	Joshua Tree	101	JOSH1	CA	34.03	116.18	2.4	2.3	2.2	2.0	2.0	1.9	2.0	2.0	2.0	2.0	1.9	2.0
Joyce Kilmer - Slickrock	Great Smoky Mountains	10	GRSM1	TN	35.43	84.00	3.3	3.1	2.9	2.7	3.3	3.8	4.0	4.2	4.2	3.8	3.3	3.5
Kaiser	Kaiser	110	KAIS1	CA	37.28	119.18	3.0	2.7	2.5	2.1	1.9	1.7	1.6	1.7	1.7	1.9	2.3	2.7
Kalmiopsis	Kalmiopsis	89	KALM1	OR	42.27	123.93	4.5	3.9	3.8	3.5	3.5	3.3	3.2	3.2	3.3	3.6	4.4	4.3
Kings Canyon	Sequoia	98	SEQU1	CA	36.82	118.76	2.8	2.6	2.4	2.1	1.9	1.8	1.7	1.7	1.8	1.9	2.3	2.5
La Garita	Weminuche	55	WEMI1	CO	37.96	106.81	2.3	2.2	1.9	1.8	1.8	1.6	1.7	2.1	2.0	1.8	2.2	2.3
Lassen Volcanic	Lassen Volcanic	90	LAVO1	CA	40.54	121.57	3.8	3.2	2.9	2.5	2.4	2.2	2.1	2.1	2.2	2.4	3.1	3.5

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Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Lava Beds	Lava Beds	87	LABE1	CA	41.71	121.34	4.0	3.4	3.1	2.7	2.6	2.4	2.3	2.3	2.4	2.7	3.5	3.8
Linville Gorge	Linville Gorge	13	LIGO1	NC	35.89	81.89	3.3	3.0	3.0	2.7	3.3	3.9	4.1	4.5	4.4	3.7	3.2	3.4
Lostwood	Lostwood	62	LOST1	ND	48.60	102.48	3.0	2.9	2.9	2.3	2.3	2.6	2.7	2.4	2.3	2.4	3.2	3.2
Lye Brook	Lye Brook	3	LYBR1	VT	43.15	73.12	2.7	2.6	2.6	2.6	2.8	3.0	3.3	3.6	3.7	3.3	2.9	2.8
Mammoth Cave	Mammoth Cave	9	MACA1	KY	37.22	86.07	3.4	3.1	2.9	2.6	3.2	3.5	3.7	3.9	3.9	3.4	3.2	3.5
Marble Mountain	Trinity	104	TRIN1	CA	41.52	123.21	4.4	3.8	3.7	3.3	3.4	3.2	3.2	3.2	3.2	3.4	4.1	4.2
Maroon Bells - Snowmass	White River	56	WHRI1	CO	39.15	106.82	2.2	2.1	2.0	2.0	2.1	1.7	1.9	2.2	2.1	1.8	2.1	2.1
Mazatzal	Ike's Backbone	46	IKBA1	AZ	33.92	111.43	2.1	1.9	1.7	1.3	1.3	1.1	1.5	1.7	1.6	1.5	1.7	2.1
Medicine Lake	Medicine Lake	63	MELA1	MT	48.50	104.29	3.0	2.9	2.9	2.3	2.2	2.5	2.5	2.2	2.2	2.4	3.2	3.2
Mesa Verde	Mesa Verde	54	MEVE1	CO	37.20	108.49	2.5	2.3	1.9	1.5	1.5	1.3	1.6	2.0	1.9	1.7	2.1	2.3
Mingo	Mingo	26	MING1	MO	36.98	90.20	3.3	3.0	2.8	2.6	3.0	3.2	3.3	3.5	3.5	3.1	3.1	3.3
Mission Mountains	Monture	73	MONT1	MT	47.40	113.85	3.6	3.1	2.7	2.5	2.6	2.6	2.3	2.2	2.5	2.9	3.5	3.6
Mokelumne	Bliss	95	BLIS1	CA	38.58	120.03	3.2	2.8	2.4	2.0	1.9	1.6	1.5	1.6	1.7	1.9	2.4	2.9
Moosehorn	Moosehorn	2	MOOS1	ME	45.12	67.26	3.0	2.7	2.7	3.0	3.0	3.1	3.4	3.8	3.9	3.5	3.2	3.2
Mount Adams	White Pass	79	WHPA1	WA	46.19	121.50	4.3	3.8	3.4	4.4	2.9	3.5	3.1	3.3	3.1	3.9	4.5	4.6
Mount Baldy	Mount Baldy	43	BALD1	AZ	34.12	109.57	2.2	2.0	1.7	1.4	1.3	1.2	1.6	1.9	1.7	1.6	1.8	2.2
Mount Hood	Mount Hood	85	MOHO1	OR	45.38	121.69	4.3	3.8	3.5	3.9	3.0	3.2	2.9	3.0	3.1	3.9	4.5	4.6
Mount Jefferson	Three Sisters	84	THSI1	OR	44.55	121.83	4.4	3.9	3.6	3.7	3.1	3.1	2.9	2.9	3.0	3.8	4.6	4.5
Mount Rainier	Mount Rainier	78	MORA1	WA	46.76	122.12	4.4	4.0	3.6	4.7	3.1	3.7	3.3	3.5	3.4	4.1	4.7	4.7
Mount Washington	Three Sisters	84	THSI1	OR	44.30	121.87	4.4	3.9	3.6	3.7	3.1	3.1	3.0	2.9	3.0	3.8	4.6	4.6
Mount Zirkel	Mount Zirkel	58	MOZI1	CO	40.55	106.70	2.2	2.2	2.0	2.1	2.2	1.9	1.7	1.9	2.0	1.9	2.1	2.1
Mountain Lakes	Crater Lake	86	CRLA1	OR	42.34	122.11	4.3	3.6	3.3	3.0	2.9	2.6	2.5	2.5	2.6	3.1	4.1	4.3
North Absaroka	North Absoraka	67	NOAB1	WY	44.77	109.78	2.4	2.3	2.2	2.2	2.1	1.9	1.7	1.6	1.8	2.0	2.4	2.4
North Cascades	North Cascades	81	NOCA1	WA	48.54	121.44	4.1	3.7	3.4	3.7	2.9	3.2	2.9	3.2	3.5	3.9	4.4	4.4
Okefenokee	Okefenokee	16	OKEF1	GA	30.74	82.13	3.5	3.2	3.1	3.0	3.6	3.7	3.7	4.1	4.0	3.8	3.5	3.6
Olympic	Olympic	83	OLYM1	WA	47.32	123.35	4.5	4.1	3.8	4.1	3.2	3.5	3.1	3.5	3.7	4.4	4.8	4.8
Otter Creek	Dolly Sods	8	DOSO1	WV	39.00	79.65	3.0	2.8	2.8	2.6	3.2	3.5	3.7	4.1	4.0	3.3	3.0	3.1
Pasayten	Pasayten	82	PASA1	WA	48.85	120.52	4.2	3.7	3.4	3.7	2.9	3.2	2.9	3.2	3.3	3.9	4.4	4.5
Pecos	Wheeler Peak	35	WHPE1	NM	35.93	105.64	2.3	2.1	1.8	1.7	1.7	1.5	1.8	2.1	2.0	1.7	2.0	2.2
Petrified Forest	Petrified Forest	41	PEFO1	AZ	35.08	109.77	2.4	2.2	1.7	1.4	1.3	1.2	1.5	1.8	1.7	1.6	1.9	2.3
Pine Mountain	Ike's Backbone	46	IKBA1	AZ	34.31	111.80	2.2	2.0	1.7	1.4	1.3	1.1	1.4	1.8	1.6	1.5	1.7	2.1
Pinnacles	Pinnacles	92	PINN1	CA	36.49	121.16	3.2	2.8	2.6	2.4	2.3	2.0	2.0	2.1	2.1	2.3	2.5	2.9
Point Reyes	Point Reyes	91	PORE1	CA	38.12	122.90	3.6	3.3	3.1	2.7	2.5	2.3	2.5	2.6	2.6	2.7	2.9	3.3
Presidential Range - Dry River	Great Gulf	4	GRGU1	NH	44.21	71.35	2.8	2.6	2.6	2.8	3.0	3.4	3.7	4.0	4.3	3.5	3.1	3.0
Rawah	Mount Zirkel	58	MOZI1	CO	40.70	105.94	2.1	2.1	2.0	2.1	2.3	2.0	1.8	2.0	2.0	1.9	2.1	2.0
Red Rock Lakes	Yellowstone	66	YELL2	WY	44.67	111.70	2.7	2.5	2.3	2.1	2.1	1.9	1.7	1.6	1.8	2.1	2.6	2.7

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Table A-3 Monthly Site-Specific f(RH) Values for Each Mandatory Federal Class I Area, Based on the Centroid of the Area (Supplemental Information)

Class I Area	Site Name	Map ID	Code	Site St	LAT	LONG	Jan f(RH)	Feb f(RH)	Mar f(RH)	Apr f(RH)	May f(RH)	Jun f(RH)	Jul f(RH)	Aug f(RH)	Sep f(RH)	Oct f(RH)	Nov f(RH)	Dec f(RH)
Redwood	Redwood	88	REDW1	CA	41.56	124.08	4.4	3.9	4.6	3.9	4.5	4.7	4.9	4.7	4.3	3.7	3.8	3.4
Rocky Mountain	Rocky Mountain	57	ROMO1	CO	40.28	105.55	1.7	1.9	1.9	2.1	2.3	2.0	1.8	2.0	1.9	1.8	1.8	1.7
Roosevelt Campobello	Moosehorn	2	MOOS1	ME	44.88	66.95	3.0	2.7	2.7	3.0	3.0	3.1	3.4	3.8	3.9	3.5	3.3	3.2
Saguaro	Saguaro	40	SAGU1	AZ	32.25	110.73	1.8	1.6	1.4	1.1	1.1	1.1	1.4	1.8	1.6	1.4	1.6	2.1
Saint Marks	Saint Marks	17	SAMA1	FL	30.12	84.08	3.7	3.4	3.4	3.4	3.5	4.0	4.1	4.4	4.2	3.8	3.7	3.8
Salt Creek	Salt Creek	36	SACR1	NM	33.61	104.37	2.1	1.9	1.5	1.5	1.7	1.6	1.8	2.0	2.1	1.8	1.8	2.1
San Gabriel	San Gabriel	93	SAGA1	CA	34.27	117.94	2.5	2.5	2.4	2.2	2.2	2.1	2.2	2.2	2.2	2.3	2.1	2.2
San Gorgonio	San Gorgonio	99	SAGO1	CA	34.18	116.90	2.7	2.8	2.6	2.3	2.2	1.9	1.8	1.9	1.9	1.9	1.9	2.2
San Jacinto	San Gorgonio	99	SAGO1	CA	33.75	116.65	2.5	2.4	2.4	2.2	2.1	2.0	2.1	2.1	2.1	2.1	2.0	2.1
San Pedro Parks	San Pedro Parks	34	SAPE1	NM	36.11	106.81	2.3	2.1	1.8	1.6	1.6	1.4	1.7	2.0	1.9	1.7	2.1	2.2
San Rafael	San Rafael	94	RAFA1	CA	34.78	119.83	2.8	2.7	2.7	2.4	2.3	2.3	2.5	2.5	2.4	2.5	2.3	2.5
Sawtooth	Sawtooth	70	SAWT1	ID	44.18	114.93	3.3	2.9	2.3	2.0	2.0	1.8	1.4	1.4	1.5	2.0	2.9	3.3
Scapegoat	Monture	73	MONT1	MT	47.17	112.73	3.2	2.8	2.6	2.4	2.5	2.4	2.1	2.0	2.3	2.6	3.1	3.1
Selway - Bitterroot	Sula	71	SULA1	MT	45.86	114.00	3.5	3.0	2.6	2.3	2.4	2.3	1.9	1.9	2.1	2.6	3.3	3.5
Seney	Seney	22	SENE1	MI	46.26	86.03	3.3	2.8	2.9	2.7	2.6	3.1	3.6	4.0	4.1	3.4	3.6	3.5
Sequoia	Sequoia	98	SEQU1	CA	36.50	118.82	2.5	2.4	2.4	2.2	1.9	1.8	1.7	1.6	1.8	1.9	2.3	2.3
Shenandoah	Shenandoah	6	SHEN1	VA	38.52	78.44	3.1	2.8	2.8	2.5	3.1	3.4	3.5	3.9	3.9	3.2	3.0	3.1
Shining Rock	Shining Rock	11	SHRO1	NC	35.39	82.78	3.3	3.0	2.9	2.7	3.4	3.9	4.1	4.5	4.4	3.8	3.3	3.4
Sierra Ancha	Sierra Ancha	45	SIAN1	AZ	33.82	110.88	2.1	2.0	1.7	1.3	1.3	1.1	1.5	1.8	1.6	1.5	1.7	2.1
Simeonof	Simeonof	105	SIME1	AK	54.92	159.28	4.3	4.1	3.6	3.9	3.9	4.3	5.0	5.2	4.5	3.8	4.0	4.3
Sipsey	Sipsey	21	SIPS1	AL	34.34	87.34	3.4	3.1	2.9	2.8	3.3	3.7	3.9	3.9	3.9	3.6	3.3	3.4
South Warner	Lava Beds	87	LABE1	CA	41.33	120.20	3.6	3.1	2.7	2.4	2.3	2.1	1.9	1.9	2.0	2.3	3.1	3.4
Strawberry Mountain	Starkey	76	STAR1	OR	44.30	118.73	3.9	3.3	2.8	2.9	2.3	2.4	2.0	2.0	1.9	2.6	3.7	4.1
Superstition	Tonto	44	TONT1	AZ	33.63	111.10	2.1	1.9	1.6	1.3	1.3	1.1	1.5	1.7	1.6	1.5	1.7	2.1
Swanquarter	Swanquarter	14	SWAN1	NC	35.31	76.28	2.9	2.7	2.6	2.5	2.9	3.2	3.4	3.5	3.4	3.1	2.8	2.9
Sycamore Canyon	Sycamore Canyon	47	SYCA1	AZ	34.03	116.18	2.4	2.3	2.2	2.0	2.0	1.9	2.0	2.0	2.0	2.0	1.9	2.0
Teton	Yellowstone	66	YELL2	WY	44.09	110.18	2.5	2.4	2.2	2.1	2.1	1.9	1.6	1.5	1.7	2.0	2.4	2.5
Theodore Roosevelt	Theodore Roosevelt	61	THRO1	ND	47.30	104.00	2.9	2.8	2.8	2.3	2.3	2.5	2.4	2.2	2.2	2.3	3.0	3.0
Thousand Lakes	Lassen Volcanic	90	LAVO1	CA	40.70	121.58	3.8	3.2	2.9	2.5	2.4	2.2	2.1	2.1	2.2	2.4	3.1	3.5
Three Sisters	Three Sisters	84	THSI1	OR	44.29	122.04	4.5	4.0	3.6	3.7	3.1	3.1	3.0	2.9	3.0	3.8	4.6	4.6
Tuxedni	Tuxedni	103	TUXE1	AK	60.15	152.60	3.5	3.3	2.9	2.7	2.7	2.9	3.6	4.0	3.9	3.5	3.5	3.7
UL Bend	UL Bend	64	ULBE1	MT	47.55	107.87	2.7	2.5	2.5	2.3	2.2	2.2	2.0	1.8	1.9	2.2	2.7	2.7
Upper Buffalo	Upper Buffalo	27	UPBU1	AR	35.83	93.21	3.3	3.0	2.7	2.8	3.4	3.4	3.4	3.4	3.6	3.3	3.2	3.3
Ventana	Pinnacles	92	PINN1	CA	36.22	121.59	3.2	2.9	2.8	2.4	2.3	2.1	2.2	2.3	2.2	2.4	2.5	2.9
Virgin Islands (b)	Virgin Islands	106	VIIS1	VI	18.33	64.79												
Voyageurs	Voyageurs	24	VOYA2	MN	48.59	93.17	2.8	2.4	2.4	2.3	2.3	3.1	2.7	3.0	3.2	2.6	2.9	2.8

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Washakie	North Absoraka	67	NOAB1	WY	43.95	109.59	2.5	2.3	2.2	2.1	2.1	1.8	1.6	1.5	1.8	2.0	2.4	2.5
Weminuche	Weminuche	55	WEMI1	CO	37.65	107.80	2.4	2.2	1.9	1.7	1.7	1.5	1.6	2.0	1.9	1.7	2.1	2.3
West Elk	White River	56	WHRI1	CO	38.69	107.19	2.3	2.2	1.9	1.9	1.9	1.7	1.8	2.1	2.0	1.8	2.1	2.2
Wheeler Peak	Wheeler Peak	35	WHPE1	NM	36.57	105.42	2.3	2.2	1.9	1.8	1.8	1.6	1.8	2.2	2.1	1.8	2.2	2.3
White Mountain	White Mountain	37	WHIT1	NM	33.49	105.83	2.1	1.9	1.6	1.5	1.5	1.4	1.8	2.0	2.0	1.7	1.8	2.1
Wichita Mountains	Wichita Mountains	30	WIMO1	OK	34.74	98.59	2.7	2.6	2.4	2.4	3.0	2.7	2.3	2.5	2.9	2.6	2.7	2.8
Wind Cave	Wind Cave	60	WICA1	SD	43.55	103.48	2.5	2.5	2.5	2.5	2.7	2.5	2.3	2.3	2.2	2.2	2.6	2.6
Wolf Island	Okefenokee	16	OKEF1	GA	31.31	81.30	3.4	3.1	3.1	3.0	3.3	3.7	3.7	4.1	4.0	3.7	3.5	3.5
Yellowstone	Yellowstone	66	YELL2	WY	44.55	110.40	2.5	2.4	2.3	2.2	2.2	1.9	1.7	1.6	1.8	2.1	2.5	2.5
Yolla Bolly - Middle Eel	Trinity	104	TRIN1	CA	40.11	122.96	4.0	3.4	3.1	2.8	2.7	2.5	2.4	2.5	2.6	2.7	3.3	3.6
Yosemite	Yosemite	96	YOSE1	CA	37.71	119.70	3.3	3.0	2.8	2.3	2.1	1.8	1.5	1.5	1.5	1.8	2.4	2.8
Zion	Zion	51	ZION1	UT	37.25	113.01	2.7	2.4	2.0	1.6	1.5	1.3	1.2	1.4	1.4	1.6	2.0	2.4

a: No particulate matter sampling or visibility monitoring is conducted in the Bering Sea Wilderness.
b: *f(RH)* values for Virgin Islands National Park were not calculated because of the limited RH data available.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-72:
EPA Carbon Dioxide Information

Carbon Dioxide Emissions

www.epa.gov/ghgemissions/carbon-dioxide-emissions

January 7, 2025

Properties of Carbon Dioxide

Chemical Formula: CO_2
Lifetime in Atmosphere: See reference[1]
Global Warming Potential (100-year): 1

On this page:

- Sources of Carbon Dioxide Emissions
- Carbon Dioxide Trends
- Reducing Carbon Dioxide Emissions

Sources of Carbon Dioxide Emissions

Carbon dioxide (CO_2) is the primary greenhouse gas emitted through human activities. In 2022, CO_2 accounted for 80% of all U.S. greenhouse gas emissions from human activities.

Carbon dioxide is naturally present in the atmosphere as part of the Earth's carbon cycle (the natural circulation of carbon among the atmosphere, oceans, soil, plants, and animals). Human activities are altering the carbon cycle, both by adding more CO_2 to the atmosphere and by influencing the ability of natural sinks, like forests and soils, to remove and store CO_2 from the atmosphere. While CO_2 emissions come from a variety of natural sources, human-related emissions are responsible for the increase that has occurred in the atmosphere since the industrial revolution.[2]

U.S. CO_2 Emissions, by Source



U.S. Carbon Dioxide Emissions, by Economic Sector

The net CO_2 flux from Land Use, Land-Use Change, and Forestry in the United States is not shown in the above diagram. All emission estimates are sourced from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2022*. Note: "Other" includes CO_2 emissions from the following sources: Natural Gas Systems, Petrochemical Production, Petroleum Systems, Incineration of Waste, Lime Production, Ammonia Production, Other Process Uses of Carbonates, Urea Consumption for Non-Agricultural Purposes, Urea Fertilization, Carbon Dioxide Consumption, Liming, Coal Mining, Glass Production, Soda Ash Production, Titanium Dioxide Production, Aluminum Production, Ferroalloy Production, Zinc Production, Phosphoric Acid Production, Lead Production, Carbide Production and Consumption, Carbon Capture and Storage, Abandoned Oil and Gas Wells, Substitution of Ozone Depleting Substances and Magnesium Production and Processing.

The main human activity that emits CO_2 is the combustion of fossil fuels (coal, natural gas, and oil) for energy and transportation. Certain industrial processes and land-use changes also emit CO_2. The main sources of CO_2 emissions in the United States are:

- **Transportation**. The combustion of fossil fuels such as gasoline and diesel to transport people and goods was the largest source of CO_2 emissions in 2022, accounting for 35% of total U.S. CO_2 emissions and 28% of total U.S. greenhouse gas emissions. This category includes domestic transportation sources such as highway and passenger vehicles, air travel, marine transportation, and rail.
- **Electricity**. Electricity is a key source of energy in the United States and is used to power homes, business, and industry. In 2022, the combustion of fossil fuels to generate electricity was the second largest source of CO_2 emissions in the nation, accounting for 30% of total U.S. CO_2 emissions and 24% of total U.S. greenhouse gas emissions. The types of fossil fuel used to generate electricity emit different amounts of CO_2. To produce a given amount of electricity, burning coal will produce more CO_2 than natural gas or oil.
- **Industry**. Many industrial processes emit CO_2 through fossil fuel consumption. Several processes also produce CO_2 emissions through chemical reactions that do not involve combustion, and examples include the production of mineral products such as cement, the production of metals such as iron and steel, and the production of chemicals. The fossil fuel combustion component of various industrial processes accounted for 16% of total U.S. CO_2 emissions and 13% of total U.S. greenhouse gas emissions in 2022. Many industrial processes also use electricity and therefore indirectly result in CO_2 emissions from electricity generation.
- **Land Use, Land-Use Change, and Forestry (LULUCF)**. In the United States, the management of forests and other land (e.g., cropland, grasslands, etc.) has acted as a net sink of CO_2, which means that more CO_2 is removed from the atmosphere, and stored in plants and trees, than is emitted. This carbon sink offset about 13% of total emissions in 2022.

Carbon dioxide is constantly being exchanged among the atmosphere, ocean, and land surface as it is both produced and absorbed by many microorganisms, plants, and animals. Emissions and removals of CO_2 by these natural processes, however, tend to balance over

time, absent anthropogenic impacts. Since the Industrial Revolution began around 1750, human activities have contributed substantially to climate change by adding CO_2 and other heat-trapping gases to the atmosphere.

To find out more about the role of CO_2 in warming the atmosphere, visit the Climate Change Indicators page.

Carbon Dioxide Trends

Carbon dioxide emissions in the United States decreased by 1.5% between 1990 and 2022, excluding LULUCF sinks. Since the combustion of fossil fuel is the largest source of greenhouse gas emissions in the United States, changes in emissions from fossil fuel combustion have historically been the dominant factor affecting total U.S. emission trends. Changes in CO_2 emissions from fossil fuel combustion are influenced by many long-term and short-term factors, including population growth, economic growth, changing energy prices, new technologies, changing behavior, and seasonal temperatures. In 2022, the increase in CO_2 emissions from fossil fuel combustion corresponded with an increase in energy use as a result of economic activity rebounding after the height of the COVID-19 pandemic, in addition to an increase in coal use in the electric power sector.

U.S. Carbon Dioxide Emissions, 1990-2022



Note: All emission estimates are sourced from the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2022*.

Image to save or print

Reducing Carbon Dioxide Emissions

The most effective way to reduce CO_2 emissions is to reduce fossil fuel consumption. Many strategies for reducing CO_2 emissions from energy are cross-cutting and apply to homes, businesses, industry, and transportation.

Strategy	Examples of How Emissions Can be Reduced
Energy Efficiency	Improving the insulation of buildings, traveling in more fuel-efficient vehicles, and using more efficient electrical appliances are all ways to reduce energy use, and thus CO_2 emissions. • See EPA's ENERGY STAR® program for more information on energy-efficient appliances and ways to save at home and work. • See EPA's and DOE's fueleconomy.gov site for more information on fuel-efficient vehicles. • Learn about EPA's motor vehicle standards that improve vehicle efficiency and save drivers money.
Energy Conservation	Reducing personal energy use by turning off lights and electronics when not in use reduces electricity demand. Reducing distance traveled in vehicles reduces petroleum consumption. Both are ways to reduce energy CO_2 emissions through conservation. Learn more about What You Can Do at Home, at School, in the Office, and on the Road to save energy and reduce your carbon footprint.
Fuel Switching	Producing more energy from renewable sources and using fuels with lower carbon contents are ways to reduce carbon emissions.
Carbon Capture and Sequestration (CCS)	Carbon dioxide capture and sequestration is a set of technologies that can potentially greatly reduce CO_2 emissions from new and existing coal- and gas-fired power plants, industrial processes, and other stationary sources of CO_2. For example, a CCS project might capture CO_2 from the stacks of a coal-fired power plant before it enters the atmosphere, transport the CO_2 via pipeline, and inject the CO_2 deep underground at a carefully selected and suitable subsurface geologic formation, such as a nearby abandoned oil field, where it is securely stored. Learn more about CCS.

Strategy	Examples of How Emissions Can be Reduced
Changes in Uses of Land and Land Management Practices	Learn more about Land Use, Land Use Change and Forestry Sector.

Examples of Reduction Opportunities for Carbon Dioxide

References

[1] Atmospheric CO_2 is part of the global carbon cycle, and therefore its fate is a complex function of geochemical and biological processes. Some of the excess carbon dioxide will be absorbed quickly (for example, by the ocean surface), but some will remain in the atmosphere for thousands of years, due in part to the very slow process by which carbon is transferred to ocean sediments.

[2] IPCC (2021). Climate Change 2021: The Physical Science Basis. *Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [Masson-Delmotte, V., P. Zhai, A. Pirani, S.L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M.I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J.B.R. Matthews, T.K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 2391 pp.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-73:
Craig Station Operating Permit



Colorado Department of Public Health and Environment

OPERATING PERMIT

Tri-State Generation & Transmission Association, Inc.

Craig Station

First Issued: May 1, 2005
Renewed: July 1, 2021

AIR POLLUTION CONTROL DIVISION
COLORADO OPERATING PERMIT

FACILITY NAME: Craig Station

OPERATING PERMIT NUMBER

96OPMF155

FACILITY ID: 081/0018

RENEWED: July 1, 2021

EXPIRATION DATE: July 1, 2026

MODIFICATIONS: See Appendix F of Permit

Issued in accordance with the provisions of Colorado Air Pollution Prevention and Control Act, 25-7-101 et seq. and applicable rules and regulations.

ISSUED TO:

Tri-State Generation & Transmission Association, Inc.
1100 W. 116th Street
Westminster, CO 80234

PLANT SITE LOCATIONS:

Craig Station
2101 S. Ranney Street
Craig, CO

INFORMATION RELIED UPON

Operating Permit Renewal Applications Received: May 1, 2009 and May 21, 2010

And Additional Information Received: Various

Nature of Business: Steam and Electricity Generation

Primary SIC: 4911

RESPONSIBLE OFFICIAL

Name: Barbara Walz

Title: Senior Vice President – Policy & Compliance Chief Compliance Officer

Phone: (303) 452-6111

FACILITY CONTACT PERSON

Name: Mike Tomasovic

Title: Environmental Supervisor

Phone: (970) 824-4411

SUBMITTAL DEADLINES –

Semi-Annual Monitoring Periods: January 1 – June 30, July 1 – December 31

Semi-Annual Monitoring Reports: Due February 1 & August 1

Annual Compliance Periods: January 1 – December 31

Annual Compliance Certification: Due February 1

Note that the Semi-Annual Monitoring Reports and Annual Compliance report must be received at the Division office by 5:00 p.m. on the due date. Postmarked dates will not be accepted for the purposes of determining the timely receipt of those reports.

SEE SECTION III OF THIS OPERATING PERMIT FOR ACID RAIN SUBMITTAL DEADLINES

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SECTION I - General Activities and Summary

1. Permitted Activities

1.1 The Tri-State Generation and Transmission Association Craig Station (herein, Source) is a coal-fired power plant with a total gross electric generating capacity of 1,375 MW. The facility operates consisting of three, pulverized coal, dry-bottom boilers: Units 1 and 2, rated at 4,318 MMBtu/hour each, were placed in service in 1980 and 1979, respectively; Unit 3, rated at 4,600 MMBtu/hour, was placed in service in 1984. All three units use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. Associated activities covered by the permit include three cooling towers, coal handling systems, ash handling systems, limestone handling systems, and lime handling systems.

Units 1 and 2 use limestone scrubbers to control SO_2 emissions; Unit 3 uses a lime spray-dryer scrubber to control SO_2 emissions. All three units use baghouses to control PM emissions, and low-NOx burners and overfire air (OFA) for NO_x emissions. Units 1 and 2 also use overfire air and related NO_x control upgrades; they are also subject to the requirements of special requirements from a 2001 revision to the Colorado State Implementation Plan. Unit 2 is equipped with a selective catalytic reduction (SCR) system, and Unit 3 is equipped with a selective non-catalytic reduction (SNCR) system for control of NO_x emissions to comply with the emission limits of the State of Colorado Regional Haze Program.

All three units are subject to the requirements of the Acid Rain Program.

The facility is located at 2101 S. Ranney Street, Craig, Colorado, Moffat County. The area in which the plant operates is designated as attainment for all criteria pollutants.

Wyoming is an affected state within 50 miles of the plant. There are two Federal Class I designated areas within 100 kilometers of the facility: Mount Zirkel National Wilderness Area and Flattops National Wilderness Area. Dinosaur National Monument is a Federal land area within 100 kilometers of the facility. Although it is not a Federal Class I area, Dinosaur has been designated by the State to have the same sulfur dioxide (SO_2) increment as a Federal Class I area.

1.2 Until such time as this permit expires or is modified or revoked, the Source is allowed to discharge air pollutants from this facility in accordance with the requirements, limitations, and conditions of this permit.

1.3 The Operating Permit incorporates the applicable requirements contained in the underlying construction permits, and does not affect those applicable requirements, except as modified during review of the application or as modified subsequent to permit issuance using the modification procedures found in Regulation No. 3, Part C. These Part C procedures meet all applicable substantive New Source Review requirements of Part B. Any revisions made using the provisions of Regulation No. 3, Part C shall become new applicable requirements for purposes of this Operating Permit and shall survive reissuance. This permit incorporates the applicable requirements (except as noted in Section II) from the following construction permits: 12MF322-1, 12MF322-2, 12MF322-3, 12MF322-4, 11MF415, 11MF332, 11MF276, 10MF579, 98MF0141, and 96MF195.

1.4 All conditions in this permit are enforceable by the United States Environmental Protection Agency (EPA), Colorado Air Pollution Control Division (hereinafter Division) and its agents, and citizens unless otherwise specified. **State-only enforceable conditions are:** Permit Condition Number(s): Section II, Conditions 3.6.3; Section V, Conditions 3.g (last paragraph), 14 & 18.

1.5 All information gathered pursuant to the requirements of this permit is subject to the Recordkeeping and Reporting requirements listed under Condition 22 of the General Conditions in Section V of this permit.

2. Alternative Operating Scenarios (AOS)

2.1 There are no AOS associated with permitted activities at the facility.

3. Prevention of Significant Deterioration (PSD)

3.1 This facility is located in an area designated attainment for all pollutants. It is categorized as a major stationary source (potential to emit ≥ 100 tons per year (tpy) for PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, and CO). Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part D, Sections II.A.27 and 44) for any pollutant as listed in Regulation No. 3, Part D, Section II.A.44 or a modification which is major by itself (i.e. a potential to emit ≥ 100 tpy of any pollutant listed in Regulation No. 3, Part D, Section II.A.44) may result in the application of the PSD review requirements.

3.2 There are no other Operating Permits associated with this facility for purposes of determining applicability of PSD regulations.

4. Accidental Release Prevention Program (112(r))

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

5. Compliance Assurance Monitoring (CAM)

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

Unit 1: PM (baghouse), SO_2 (wet scrubber)

Unit 2: PM (baghouse), NO_x (SCR), SO_2 (wet scrubber)

Unit 3: PM (baghouse), NO_x (SNCR), SO_2 (lime spray-dryer)

P102 – Coal Handling System, S102d – Secondary Coal Crushing Building: PM (baghouse)

6. Summary of Emission Units

6.1 The emissions units regulated by this permit are the following:

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
Unit 1 Boiler	B001	001	S001	Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	10MF579	Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air
Unit 2 Boiler	B002	002	S002	Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization		Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air SCR
Unit 3 Boiler	B003	003	S003	Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	12MF322-1	Spray dryer Baghouse Low-NO_x burners with overfire air SNCR
Coal Handling – Units 1 & 2	P101	004	F101a	Coal hauling – Units 1 & 2	11MF276	$MgCl_2$, water, or equivalent application, as necessary
			F101b	Coal unloading to grizzly – Units 1 & 2		Water spray with surfactant, as necessary
			F101c	Coal surge pile		Water with surfactant, as necessary
			S101d	Primary coal crushing – Units 1 & 2		Baghouse
			S101e	Secondary coal crushing building – Units 1 & 2		Baghouse
			S101f	Common coal transfer building belt A		Baghouse
			S101g	Common coal transfer building belt B		Baghouse
			S101h	Coal stackout building – Units 1 & 2		Baghouse
			F101i	Coal stackout – Units 1 & 2		Telescopic chute
			F101j	Coal storage piles – Units 1 & 2		Water spray prior to stackout, as necessary
			S101k	Coal reclaim A – Units 1 & 2		Baghouse

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
			S101l	Coal reclaim B – Units 1 & 2		Baghouse
			S101m	Coal tripper deck & silos – Units 1 & 2		Baghouse
Ash Handling – Units 1 & 2	P203	016	S203a	Ash storage silo A – Units 1 & 2	11MF332	Baghouse (Shared with S203e)
			S203b	Ash storage silo B – Units 1 & 2		Baghouse (Shared with S203d)
			F203c	Ash truck loading – Units 1 & 2		Low dust unloading system
			S203d	Silo B dry ash unloading – Units 1 & 2		Baghouse (Shared with S203b)
			S203e	Silo A dry ash unloading – Units 1 & 2		Baghouse (Shared with S203a)
Limestone Handling – Units 1 & 2	P201	020	F201a	Limestone hauling	11MF415	Paved portions of road
			S201b	Limestone truck unloading		Baghouse
			S201c	Limestone silo #1 – Units 1 & 2		Baghouse
			S201d	Limestone silo #2 – Units 1 & 2		Baghouse
Coal Handling – Unit 3*	P102*	023	F102a	Coal train unloading – Unit 3	12MF322-2	Water spray
			S102b	Coal conveyor portal building – Unit 3		Baghouse
			S102c	Coal conveyor portal building – Unit 3		Baghouse
			S102d	Secondary coal crushing (2 crushers) – Unit 3		Baghouse
			S102e	Coal stackout building – Unit 3		Baghouse
			F102f	Coal stackout – Unit 3		Telescopic chutes
			F102g	Coal storage pile – Unit 3		PM control plan, including compaction, chemical use or watering, as necessary
			S102h	Coal reclaim system – Unit 3		Baghouse
			S102i	Coal tripper deck & silos – Unit 3		Baghouse
			S102j	Loadout coal to railcars – Unit 3		Baghouse
			S102k	Common coal transfer building extension		Baghouse
			F102l	Coal train loading		None
Ash Handing – Unit 3	P204	032	S204a	Ash storage silo – Unit 3	12MF322-3	Baghouse
			F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3		Low dust loader (wet ash) Baghouse (dry flyash)

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
			S204c	Recycle ash tank		Baghouse
			F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3		$MgCl_2$ application on roads, as necessary
Lime Handling and Storage – Unit 3	P202	035	F202a	Lime hauling	12MF322-4	Paved portions of road
			S202b	Lime unloading		Baghouse
			S202c	Lime conveying and silo		Baghouse
			S202d	Lime day bin		Baghouse
Cooling Towers – Units 1 & 2	P401	040	S401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74, ten cells with BACT compliant drift eliminators	96MF195	Drift eliminators
	P402		S402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74, ten cells with BACT compliant drift eliminators		Drift eliminators
Unit 3 Cooling Tower	P403	044	S403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79, ten cells with BACT compliant drift eliminators	98MF0141	Drift eliminators
Emergency Diesel Fire-Pump Engine	N/A	N/A	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower	N/A	None
Units 1&2 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower	N/A	None
Unit 3 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower	N/A	None

*Note that the Unit 3 coal handling system is occasionally used to blend coal for Units 1 and 2

Table 1 - Craig Station Emission Unit Summary

SECTION II - Specific Permit Terms

1. Boiler B001 "Unit 1" – Coal-fired boiler, Babcock & Wilcox #NB24157, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	1.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 1.1
SO_2	1.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	1.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.28 lb/MMBtu 30-day rolling average (CO Reg. 23, IV.D.2.) 4,065 tpy calendar year basis (CO Reg. 23, Section IV.D.3., see Condition 1.10) 0.46 lb/MMBtu calendar year average (see Acid Rain requirements in Section III)			
VOC & CO	1.4		See Condition 1.4	Recordkeeping and Calculation	Annually
Opacity	1.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, CO Reg. 6, Part A, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Coal Requirements	1.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	1.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 1.7	
NSPS D	1.8	See Condition 1.8			
CO SIP	1.9	See Condition 1.9			
Regional Haze	1.10	PM: 0.03 lb/MMBtu (See Condition 1.1) SO_2: 0.11 lb/MMBtu 30-boiler operating day rolling average (See Condition 1.2) NO_x: 0.28 lb/MMBtu (Condition 1.3) NO_x: 4,065 tpy (Condition 1.3)		CEMS	Continuous
Acid Rain	1.11	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	1.12	See Condition 1.12 and 5			
CAM	1.13	See Condition 1.13			

Table 2 - Unit 1 Emissions and Requirements Summary

1.1 **Particulate matter (PM)** emissions must not exceed the following limits:

1.1.1 **0.10 lb PM/MMBtu heat input**, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

1.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 1 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

1.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.1.2 **0.03 lb PM/MMBtu heat input**, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3 **0.03 lb PM/MMBtu heat input**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

1.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

1.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 1.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 1.13 (Colorado Regulation No. 23, Section V.B.1.).

1.1.4 **0.03 lb PM/MMBtu heat input**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

1.1.5 To **demonstrate compliance** with the PM emission limits in Condition 1.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and conduct periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 1.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6, unless a PM_{10} emission factor was developed using source testing.

1.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

1.2.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

1.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

1.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.2.2 **1.2 lb/MMBtu heat input, three-hour rolling average**, Colorado Regulation No. 1, Section VI.A.

1.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

1.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

1.2.3 **0.11 lb/MMBtu, 30-day rolling average**, Colorado Regulation No. 23, Section IV. – Regional Haze and Colorado Regional Haze SIP

1.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 1.2.5.

1.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.2.3.3 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.4 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.2.3.3, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.5 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.6 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.2.3.3. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.2.3.7 The Source must maintain records and follow the reporting requirements as described in Condition 1.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

1.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.2.4.1 The Source must **treat one hundred percent (100%) of the flue gas** from Unit 1 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 1.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

Note that in determining compliance with the requirements of Condition 1.2.4, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions.

1.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. **0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis**;

b. **0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis**.

1.2.4.3 **SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis** as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 1.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days

(including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 1.9;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

1.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 1.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

1.2.5 Compliance calculations for SO_2 requirements in Condition 1.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

1.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

1.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

1.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

1.3.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

1.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

1.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with NO_x in excess of **0.30 lb/MMBtu heat input on a calendar year annual average basis**. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 1.7.

1.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

1.3.3 **0.28 lb/MMBtu, 30-day rolling average**, Colorado Regulation No. 23, Section IV.D.2. – Regional Haze, as provided for in Condition 1.10

1.3.3.1 The Source must comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.2 At all times, the Source must maintain, calibrate, and operate a CEMS in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.3.3.1, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source must calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.3 In determining compliance with the NO_x regional haze limit, all periods of emissions must be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.4 For any hour in which fuel is combusted, the Source must calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.3.3.1. These hourly averages must be used to determine compliance in accordance with the averaging period, as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source must calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.3.3.5 Compliance shall be monitored using the CEMS as described in Condition 1.3.5.

1.3.3.6 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.3.4 Craig Unit 1 must meet an **annual NO_x limit of 4,065 tons per year by December 31, 2020** on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.)

1.3.5 Compliance calculations for NO_x requirements in Condition 1.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

a. Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

1.3.5.2 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

1.3.6 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

1.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 1.6.1 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

1.5 **Opacity**

1.5.1 Colorado Regulation No. 1

1.5.1.1 Except as provided in Condition 1.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

1.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

1.5.2 40 CFR Part 60, Subpart D

1.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

1.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

1.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control

equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

1.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

1.5.3.3 An opacity reading in excess of the limitations in Condition 1.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 1.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

1.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

1.5.4 Compliance with the opacity emissions limitations in Condition 1.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an

intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4. (Colorado Regulation No. 3, Part C, Section V.C.5.)

1.5.4.1 The requirements for the COMS system are outlined in Condition 19.

1.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

1.5.5 **Partial streamlining of opacity limits into State Implementation Plan opacity limits** – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS Subpart D (Conditions 1.5.1 and 1.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 1.5.3), except as follows:

1.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 1.5.1 and 1.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

1.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 1.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 1.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

1.6 Coal Requirements

1.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.7 Continuous Emissions Monitoring Systems (CEMS)

1.7.1 For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

1.7.2 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

1.8 40 CFR Part 60, Subpart D

1.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

1.8.2 In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

1.8.3 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

1.8.4 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and monitoring system performance (MSP) report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

1.8.4.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

1.8.4.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 1.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

1.8.4.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 1.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

1.8.5 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

1.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 1 in a manner consistent with good air pollution control practices for minimizing emissions.

1.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

1.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

1.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

1.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

1.10 Colorado Regulation No. 23, Regional Haze

1.10.1 Craig Unit 1 will close on or before December 31, 2025 (Colorado Regulation No. 23, Section IV.D.1.).

1.10.2 As provided in Condition 1.3.3, Craig Unit 1 will meet a **NO_x emission limit of 0.28 lb/MMBtu over a 30-day rolling average** going forward from January 1, 2017 (first compliance date January 31, 2017), until closure (Colorado Regulation No. 23, Section IV.D.2.).

1.10.3 As provided in Condition 1.3.4, Craig Unit 1 will meet an annual **NO_x limit of 4,065 tons per year by December 31, 2019** on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.).

1.10.4 Compliance with the 30-day rolling average and annual NO_x limits will be monitored using the CEMS as described in Condition 19.

1.10.5 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

1.10.5.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

1.10.5.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

1.10.5.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

1.10.5.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

1.10.5.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

1.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

1.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 1 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

1.13 Compliance Assurance Monitoring (CAM)

Unit 1 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 1.1, and the SO_2 emissions in Condition 1.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G and J.

2. Boiler B002 "Unit 2" – Coal-fired boiler, Babcock & Wilcox #NB24156, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	2.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 2.1
SO_2	2.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	2.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.08 lb/MMBtu 30-day rolling average (CO Reg. 23, Section IV) 0.46 lb/MMBtu (see Acid Rain requirements in Section III)			
VOC & CO	2.4		See Condition 2.4	Recordkeeping and Calculation	Annually
Opacity	2.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals
Coal Requirements	2.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	2.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 2.7	
NSPS D	2.8	See Condition 2.8			

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
CO SIP	2.9	See Condition 2.9			
Regional Haze	2.10	PM: 0.03 lb/MMBtu (See Condition 2.1) SO_2: 0.11 lb/MMBtu 30-day rolling average (See Condition 2.2) NO_x: 0.08 lb/MMBtu 30-day rolling average (See Condition 2.3)		CEMS	Continuous
Acid Rain	2.10.2	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	2.12	See Condition 2.12 and 5			
CAM	2.13	See Condition 2.13			

Table 3 – Unit 2 Emissions and Requirements Summary

2.1 **Particulate matter (PM)** emissions must not exceed the following limits:

2.1.1 **0.10 lb/MMBtu heat input**, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

2.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 2 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

2.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.1.2 **0.03 lb/MMBtu heat input**, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3 **0.03 lb/MMBtu heat input**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 2.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 2.13 (Colorado Regulation No. 23, Section V.B.1.).

2.1.4 **0.03 lb PM/MMBtu heat input**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

2.1.5 To **demonstrate compliance** with the PM emission limits in Condition 2.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and by conducting periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.).:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6; unless a PM_{10} emission factor was developed using source testing.

2.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

2.2.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

2.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

2.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.2.2 **1.2 lb/MMBtu, three-hour rolling average**, Colorado Regulation No. 1, Section VI.A.

2.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

2.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

2.2.3 **0.11 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 2.2.5.

2.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.2.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.2.3.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.2.3.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.2.3.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.2.3.8 The Source must maintain records and follow the reporting requirements as described in Condition 2.9.3, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

2.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.2.4.1 The Source must **treat one hundred percent (100%) of the flue gas** from Unit 2 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 2.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

2.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. 0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis;

b. 0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis.

2.2.4.3 **SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis** as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 2.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 19.4;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

2.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 2.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

2.2.5 Compliance calculations for SO_2 requirements in Condition 2.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

2.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

2.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

2.3.1 **40 CFR Part 60, Subpart D** – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25

percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

2.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

2.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with **NO_x in excess of 0.30 lb/MMBtu heat input on a calendar year annual average basis**. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 2.7.

2.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

2.3.3 **0.08 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV – Regional Haze, as provided for in Condition 2.9.3

2.3.3.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.3.3.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.3.3.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.4 In determining compliance with the NO_x regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.3.3.2. These hourly average

shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.3.3.6 Compliance shall be monitored using the CEMS as described in Condition 2.3.4.

2.3.3.7 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.102.9.3.

2.3.4 Compliance calculations for NO_x requirements in Condition 2.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3.4.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.3.4.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

2.3.4.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

2.3.5 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

2.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

2.5 **Opacity**

2.5.1 Colorado Regulation No. 1

2.5.1.1 Except as provided in Condition 2.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

2.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

2.5.2 40 CFR Part 60, Subpart D

2.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

2.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

2.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

2.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

2.5.3.3 An opacity reading in excess of the limitations in Condition 2.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 2.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

2.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

2.5.4 Compliance with the opacity emissions limitations in Condition 2.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.5.4.1 The requirements for the COMS system are outlined in Condition 19.

2.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity

observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

2.5.5 **Partial streamlining of opacity limits into State Implementation Plan opacity limits** – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 2.5.3), except as follows:

2.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

2.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 2.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 2.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

2.6 Coal Requirements

2.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired

belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.7 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

2.7.1 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A. (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

2.8 40 CFR Part 60, Subpart D

2.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

2.8.2 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

2.8.3 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in

§60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

2.8.3.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

2.8.3.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 2.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

2.8.3.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 2.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

2.8.4 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

2.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 2 in a manner consistent with good air pollution control practices for minimizing emissions.

2.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

2.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

2.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

2.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

2.10 **Colorado Regulation No. 23, Regional Haze**

2.10.1 Craig Unit 2 will close no later than September 30, 2028 (Colorado Regulation No. 23, Section IV.F.1.e.).

2.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

2.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

2.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

2.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

2.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

2.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

2.11 **Acid Rain**

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

2.12 **40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units**

Unit 2 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

2.13 **Compliance Assurance Monitoring (CAM)**

Unit 2 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 2.1, the SO_2 limitations in Condition 2.2, and the NO_x limitations in Condition 2.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G, J, and L.

3. Boiler B003 "Unit 3" – Coal-fired boiler, Babcock & Wilcox #NB24602, 4600 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	3.1	443 tons/year, 12-month rolling total 0.03 lb/MMBtu (Filterable, MATS) 0.013 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)	Stack Performance Testing	Baghouse O&M Stack Performance Testing	Continuous See Condition 3.1
PM_{10}		403 tons/year, 12-month rolling total 0.012 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)			
SO_2	3.2	2,125 tons/year 0.20 lb/MMBtu, daily average, except one daily average per month which may exceed 0.20 lb/MMBtu (BACT) 80% reduction of potential emissions, 30-day average (BACT) 1.20 lb/MMBtu, 90% reduction of potential emissions; 70% reduction of potential emissions when emissions are less	CEMS	CEMS Stack Performance Testing Coal Sampling, Calculation, Recordkeeping	Continuous See Condition 3.2 Daily

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		than 0.60 lb/MMBtu, 30-day rolling average (NSPS Da) 0.4 lb/MMBtu, 3-hour rolling average (CO Reg 1) 0.15 lb/MMBtu, 30-day rolling average (CO Reg 23) 0.20 lb/MMBtu, 30-day rolling average (MATS)			
NOx	3.3	6,752 tons/year 0.50 lb/MMBtu, 30-boiler operating day rolling average (NSPS Da & BACT) 0.28 lb/MMBtu, 30-boiler operating day rolling average (CO Reg 23)	CEMS	CEMS	Continuous
CO	3.4	4,332 tons/year 1.25 lb/MMBtu, 8-hour rolling average (BACT)	CEMS	CEMS	Continuous
VOC	3.5	58 tons/year	0.003 lb/MMBtu, or AP-42, EPRI, stack test data	Recordkeeping and Calculation	Monthly
Lead (Pb)		0.054 tons/year	2.82 lb/TBtu, or AP-42, EPRI, stack test data		
Sulfuric Acid Mist (SAM)		0.10 tons/year	See Condition 3.5		
Fluorides		4.47 tons/year	232.74 lb/TBtu, or AP-42, EPRI, stack test data		
Opacity	3.6	Not to exceed 10% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT)		COMS – May be verified by EPA Reference Method 9	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		During startup and shutdown, not to exceed 20% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT) Not to exceed 20% except during certain operational condition during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg 1) Not to exceed 20% (CO Reg 6 – State-only)			
Coal Requirements	3.7	1,897,344 tons/year Coal sampling		Recordkeeping ASTM Methods	Monthly Quarterly
CEMS	3.8	Monitor: Opacity, NO_x, SO_2, CO, CO_2, diluent gas, flow		See Condition 3.8	
NSPS Da	3.9	See Condition 3.9			
Regional Haze	3.10	See Condition 3.10			
Acid Rain	3.10.2	See Section III of this Operating Permit		Certification	Quarterly and Annually
MACT UUUUU (MATS)	3.12	See Conditions 3.12 and 5			
CAM	3.13	See Condition 3.13			

Table 4 – Unit 3 Emissions and Requirements Summary

3.1 **Particulate matter (PM) and particulate matter less than or equal to 10 microns (PM_{10})** emissions must not exceed the following limits:

3.1.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for PM and PM_{10}. The Division and the EPA have determined that the following limits meet the

BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.1.1.1 **[Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu**

a. Compliance with the filterable PM limit will be monitored by stack testing as required in Condition 3.1.4. Compliance with the filterable PM_{10} limit will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.2 **[Total Filterable and Condensable] 0.018 lb PM/MMBtu heat input, 0.018 lb PM_{10}/MMBtu**

a. Compliance with these limits will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.3 **[Total Filterable and Condensable] 443 tons PM/year, 403 tons PM_{10}/year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Compliance with these limits will be monitored per the requirements in Condition 3.1.4.

3.1.2 **[Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu**, Colorado Regulation No. 23, Section IV.B.

3.1.2.1 Compliance with this limit will be monitored by the stack testing as required in Condition 3.1.4 and by demonstrating compliance with the CAM plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 3.13 (Colorado Regulation No. 23, Section V.B.1.).

3.1.2.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.1.2.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.B.3.).

3.1.3 **0.03 lb PM/MMBtu**, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

3.1.4 To **demonstrate compliance** with PM and PM_{10} emission limits in Condition 3.1, the Source must:

3.1.4.1 For filterable $PM_{10,}$ and total filterable and condensable emission limitations compliance shall be monitored by conducting performance tests as required by Condition 17.

3.1.4.2 The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.1.4.3 For annual filterable and condensable emission limitations, compliance shall be monitored by calculating emissions using the total PM and PM_{10} emission factors from the most recent performance test, and the monthly quantity of heat input to the boiler in the following equation:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use} * \left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The monthly heat input to the boiler shall be determined using the monthly coal consumption and the average heat content of the coal, as determined by the coal sampling as required in Condition 3.7.3. Monthly emissions shall be used in a rolling twelve-month total to monitor compliance with the annual limitation. Each month a new twelve-month total shall be calculated using the previous twelve-months' data.

3.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

3.2.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for SO_2. The Division and the EPA have determined that the following limits meet the BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.2.1.1 **0.20 lb/MMBtu heat input**, as averaged over any calendar day, to be exceeded no more than once during any calendar month.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with this emission limitation is determined by calculating the arithmetic average emissions for any calendar day from the individual hourly values, for each Unit Operating Hour, defined as "a clock hour during which a unit combusts any fuel, either for part of the hour or for the entire hour," by 40 CFR Part 72, §72.2.

3.2.1.2 **80% reduction of the potential combustion concentration of SO_2**, as determined on a 30-day rolling average basis.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with the percentage reduction requirement is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day, and a new 30-boiler operating day rolling average emission rate and a new percent reduction for SO_2 are calculated to show compliance with the standards (40 CFR Part 60, §60.48Da(b)).

c. Compliance is determined by calculating the arithmetic average of all valid hourly emission rates for SO_2 for the 30 successive boiler operating days. Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.1.3 **2,125 tons of SO_2 per year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

3.2.1.4 Compliance with these limits shall be monitored using the CEMS as required in Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.2.2 40 CFR Part 60, Subpart Da, §60.43Da

3.2.2.1 When combusting solid fuel, as applicable, the Source shall not emit into the atmosphere any gases which contain SO_2 emissions in excess of either (40 CFR Part 60, §60.43Da(a):

a. 520 ng/J (**1.20 lb/MMBtu**) heat input and 10 percent of the potential combustion concentration (**90 percent reduction**) (40 CFR Part 60, §60.43Da(a)(1));

b. 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

c. 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

d. 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

3.2.2.2 This SO_2 emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.2.2.3 Compliance with the applicable SO_2 emission limit and percentage reduction requirements under 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for SO_2 and a new percent reduction for SO_2 are calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.2.2.4 Compliance with the applicable 30-boiler operating day rolling average for SO_2 emission limits is determined by calculating the arithmetic average of all hourly emission rates for SO_2 for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.2.2.5 Compliance with the applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.2.6 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.2.2.7), compliance with the SO_2 emission requirements in §60.43Da (Condition 3.2.2.1) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part

60, §60.48Da(h)).

3.2.2.7 The Source shall calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, as follows: (40 CFR Part 60, §60.49Da(b)).

a. Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2 control device (40 CFR Part 60, §60.49Da(b)(1)).

b. For a facility that qualifies under the numerical limit provisions of §60.43Da, SO_2 emissions are only monitored as discharged to the atmosphere (40 CFR Part 60, §60.49Da(b)(2)).

c. An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of Appendix A to 40 CFR Part 60 may be used to determine potential SO_2 emissions in place of a continuous SO_2 emission monitor at the inlet to the SO_2 control device as required under §60.49Da(b)(1) (Condition 3.2.2.7.a.) (40 CFR Part 60, §60.49Da(b)(3)).

d. If the Source has installed and certified an SO_2 CEMS according to the requirements of §75.20(c)(1) of 40 CFR Part 75 and Appendix A of Part 75, and is continuing to meet the ongoing QA requirements of 40 CFR Part 70, §75.21 and Appendix B of Part 75, that CEMS may be used to meet the requirements of §60.49Da(b) (Condition 3.2.2.7), provided that the following conditions are met (40 CFR Part 60, §60.49Da(b)(4)):

(i) A CO_2 or O_2 (continuous monitoring system) CMS is installed, calibrated, maintained and operated at the same location, according to §60.49Da(d) (Condition 3.2.2.7.e.) (40 CFR Part 60, §60.49Da(b)(4)(i)); and

(ii) For Sources subject to an SO_2 emission limit in lb/MMBtu under §60.43Da (40 CFR Part 60, §60.49Da(b)(4)(ii)):

a) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously (40 CFR Part 60, §60.49Da(b)(4)(ii)(A)); and

b) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of 40 CFR Part 75, Appendix B, the relative accuracy standard in section 13.2 of Performance Specification 2 in Appendix B to Part 75 is met when the relative accuracy is calculated on a lb/MMBtu basis (40 CFR Part 60, §60.49Da(b)(4)(ii)(B)); and

(iii) The reporting requirements of §60.51Da are met. The SO_2 and, if required, CO_2 (or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures of 40 CFR part 75, nor shall the SO_2 data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 75, §60.49Da(b)(4)(iii)).

e. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where SO_2 emissions are

monitored. For affected facilities subject to a lb/MMBtu SO_2 emission limit under §60.43Da (Condition 3.2.2.1), if the Source has installed and certified a CO_2 or O_2 monitoring system according to 40 CFR Part 75, §75.20(c) and Appendix A to Part 75 and the monitoring system continues to meet the applicable QA provisions of 40 CFR Part 75, §75.21 and Appendix B of Part 75, that CEMS may be used together with the Part 75 SO_2 concentration monitoring system described in §60.49Da(b) (Condition 3.2.2.7), to determine the SO_2 emission rate in lb/MMBtu. SO_2 data used to meet the requirements of §60.51Da (Condition 3.9.2) shall not include substitute data values derived from the missing data procedures in 40 CFR Part 75, Subpart D, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(d)).

f. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

g. Additional CEMS requirements are described in Condition 3.8.

3.2.2.8 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for SO_2. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.2.2.9 The Source shall demonstrate compliance with the SO_2 standards in 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) as described in §60.50Da(c)(1) through (5) (40 CFR Part 60, §60.50Da(c)).

3.2.2.10 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.2.3 **0.4 lb/MMBtu heat input, 3-hour rolling average**, Colorado Regulation No. 1, Section VI.B.4.

3.2.3.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 0.4 lb SO_2/MMBtu heat input (Colorado Regulation No. 1, Section VI.B.4.a.(iii)).

3.2.3.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.B.2.).

3.2.4 **0.15 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV.B.

3.2.4.1 Compliance with this limit will be monitored by the CEMS as required in Condition 3.8 (Colorado Regulation No. 23, Section V.A.1.).

3.2.4.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.2.4.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.2.4.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.2.4.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.2.4.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.2.5 Compliance calculations for SO_2 requirements in Condition 3.2, with the exception of the annual emission limit in Condition 3.2.1.3, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 3.8. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

3.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period

of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

3.2.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.2.1.3, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr SO_2 emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.2.6.1 Hourly mass SO_2 emissions (in lbs/hr) shall be determined by taking the hourly 40 CFR Part 75 SO_2 ppm value (which includes replaced or bias-adjusted data, as applicable), multiplying it by the hourly 40 CFR Part 75 stack flow rate (which includes replaced or bias adjusted data, as applicable) and the multiplying it by the applicable conversion factor. The resulting SO_2 lb/hr value (which is calculated using the appropriate equation in Appendix F of 40 CFR Part 75) is then multiplied by the unit operating time for that hour to produce a SO_2 lbs value. Hourly SO_2 mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly SO_2 emissions (in tons).

3.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3 **Nitrogen oxides (NO_x)** emissions must not exceed the following limits:

3.3.1 **0.50 lb/MMBtu heat input, 30 consecutive boiler operating-day rolling average**, Colorado Construction Permit 12MF322-1 The Source must comply with Best Available Control Technology (BACT) requirements for NO_x. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

3.3.1.1 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.1.2 Compliance with the NO_x emission limitation is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day and a new 30 day average emission rate for nitrogen oxides is calculated to show compliance with the standard (40 CFR Part 60, §60.48Da(b)).

3.3.1.3 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.1.4 Compliance with this limit shall be monitored using the CEMS as required in

Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.3.2 **6,752 tons of NO_x per year**, Colorado Construction Permit 12MF322-1

3.3.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.8.

3.3.3 40 CFR Part 60, Subpart Da

3.3.3.1 For coal-derived solid fuels: **0.50 lb/MMBtu heat input**, 30-day rolling average (40 CFR Part 60, §60.44Da(a)(1) & §60.44Da(e)).

3.3.3.2 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.3.3 Compliance with the applicable NO_x emission limit requirements under 40 CFR Part 60, §60.44Da (Condition 3.3.3) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for NO_x is calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.3.3.4 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.3.5 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.3.3.6), compliance with the NO_x emission requirements in §60.44Da (Condition 3.3.3) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part 60, §60.48Da(h)).

3.3.3.6 The Source shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_x emissions discharged into the atmosphere (40 CFR Part 60, §60.49Da(c)(1)); or

If the Source has installed a NO_x emission rate CEMS to meet the requirements of 40 CFR Part 75 and is continuing to meet the ongoing requirements of 40 CFR Part 75, that CEMS may be used to meet the requirements of this section, except that the Source shall also meet the requirements of §60.51Da (Condition 3.9.2). Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in Subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(c)(2)).

a. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where NO_x emissions are monitored (40 CFR Part 60, §60.49Da(d)).

b. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

c. Additional CEMS requirements are described in Condition 3.8.

3.3.3.7 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for NO_x. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.3.3.8 The Source shall determine compliance with the NO_x standard in 40 CFR Part 60, §60.44Da (Condition 3.3.3) as follows (40 CFR Part 60, §60.50Da(d)):

a. The appropriate procedures in Method 19 of Appendix A of 40 CFR Part 60 shall be used to determine the emission rate of NO_x (40 CFR Part 60, §60.50Da(d)(1)).

b. The continuous monitoring system in 40 CFR Part 60, §60.49Da(c) & (d) (Condition 3.3.3.6) shall be used to determine the concentrations of NO_x and CO_2 or O_2 (40 CFR Part 60, §60.50Da(d)(2)).

3.3.3.9 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.3.4 **0.28 lb/MMBtu, based on a 30-day rolling average**, Colorado Regulation No. 23, Section IV.B.

3.3.4.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.3.4.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.3.4.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.4 In determining compliance with the NO_x regional haze limit, all periods of emissions

shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.3.4.2. These hourly averages shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.3.4.6 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

3.3.5 Compliance calculations for NO_x requirements in Condition 3.3, with the exception of the annual emission limitation in Condition 3.3.2, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the 30-day rolling average calculations.

3.3.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

3.3.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.3.2, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr NO_x emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.3.6.1 Hourly mass NO_x emissions (in lb/hr) shall be calculated by multiplying the hourly 40 CFR Part 75 NO_x lb/MMBtu value (which includes replaced or bias-adjusted data, as applicable) by the hourly heat input rate (MMBtu/hr) (which includes replaced and bias-adjusted data from the stack flow and % CO_2 measurements, as applicable). The hourly NO_x lb/MMBtu and heat input values are determined using the relevant equations in Appendix F of 40 CFR Part 75. The resulting NO_x lb/hr value is then multiplied by the unit operating time for that hour to produce a NO_x lbs value. Hourly

NO_x mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly NO_x emissions (in tons).

3.4 Carbon Monoxide (CO)

3.4.1 Colorado Construction Permit 12MF322-1

3.4.1.1 Good combustion practices shall be used to limit CO emissions to **1.25 lb/MMBtu on an 8-hour rolling average**. The Source must comply with Best Available Control Technology (BACT) requirements for CO. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

a. Compliance with this limit shall be monitored using the CO CEMS as required by Condition 3.4.2. The lb/MMBtu emission factor will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.4.1.2 **4,332 tons of CO per year**

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.4.2.

b. Monthly emissions shall be calculated by multiplying the average monthly emission rate in lb/MMBtu by the total monthly heat input in mmBtu, then converting to tons by dividing by 2000 lb//ton.

3.4.2 Compliance with the CO limits in Condition 3.4 must be monitored using a CO CEMS in accordance with the requirements of Conditions 3.8 and 19, and in accordance with the following:

3.4.2.1 For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average CO concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4.

3.5 Volatile Organic Compounds (VOC), Lead (Pb), Sulfuric Acid Mist (SAM), and Fluorides

3.5.1 The Source shall not cause to be emitted into the atmosphere VOC, Pb, SAM, or fluorides in excess of the following limits:

3.5.1.1 **VOC: 58 tons per year**

3.5.1.2 **Lead (Pb): 0.054 tons per year**

3.5.1.3 **Sulfuric Acid Mist (SAM): 0.10 tons per year**

3.5.1.4 **Fluorides: 4.47 tons per year**

3.5.2 Compliance with the annual limits in Condition 3.5.1 shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be calculated using actual fuel heating values as determined by the required testing in Condition 3.7.3, the actual fuel usage, and Division approved emission factors (the current emission factor as listed in Table 4, AP-42, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.), in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton}{month} = Emission\ Factor\ \left[\frac{lb}{MMBtu}\right] * Fuel\ Heat\ Content\ \left[\frac{MMBtu}{ton\ coal}\right] * Fuel\ Use\ \left[\frac{ton\ coal}{month}\right] * \frac{1\ ton}{2000\ lb}$$

3.6 Opacity

3.6.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for opacity. The Division and the EPA have determined that the following limits meet the BACT requirements and that the BACT limits apply at all times, as specified.

3.6.1.1 Except as provided for in Conditions 3.6.1.2 and 3.6.1.3, the Source may not allow or cause the emission into the atmosphere any gases in excess of 10 percent (%) opacity, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.1.2 During periods of startup and shutdown, opacity must not exceed 20%, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

a. "Startup" means the setting in operation of any air pollution source for any purpose. Startup commences when the ID/FD fans are started with the intent to purge the furnace prior to returning Unit 3 to service. Startup ends at such time when either a third scrubber reactor is placed online or when the average scrubber inlet temperature reaches 250 degrees Fahrenheit, or when the startup is stopped for any reason and the unit drops to zero load.

b. "Shutdown" means the cessation of operation of any air pollution source for any purpose. The cessation of operation for Unit 3 begins when the command signal is initiated by the unit operator to shutdown the unit and ends when fuel is no longer being fired and the fans have been shut off.

3.6.1.3 During the five-day period following the return of each and every baghouse compartment to service following bag replacement, reattachment, and retensioning, up to 20% opacity shall be allowed for no more than a total of 30 six-minute periods during each five-day period following such work, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.2 Colorado Regulation No. 1

3.6.2.1 Except as provided in Condition 3.6.2.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

3.6.2.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

3.6.3 Colorado Regulation No. 6 [State-only requirement]

3.6.3.1 The Source must not discharge, or cause the discharge into the atmosphere any particulate matter which is in excess of 20% opacity (Colorado Regulation No. 6, Part B. Section II.C.3.). This standard applies at all times except during periods of startup, shutdown, or malfunction

3.6.3.2 In addition, the requirements of Colorado Regulation No. 6, Part A, Subpart A; General Provisions, apply. These requirements include the 40 CFR Part 60, Subpart A, General Provisions which include but are not limited to the requirements described in Condition 18.

3.6.4 Compliance with the opacity emissions limitations in Condition 3.6 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4.

3.6.4.1 The requirements for the COMS system are outlined in Conditions 3.8 and 19.

3.6.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

3.7 Coal Requirements

3.7.1 Consumption of coal must not exceed 1,897,344 tons per year (Colorado Construction Permit 12MF322-1).

3.7.1.1 Compliance with the annual throughput limit shall be determined on a rolling twelve-month total. By the end of each new month a new twelve-month total is calculated based on the previous twelve-months' data.

3.7.2 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years.

3.7.3 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20.

3.8 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO, CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

3.9 40 CFR Part 60, Subpart Da

3.9.1 **Affirmative defense** for exceedance of emissions limit during malfunction, 40 CFR Part 60, §60.48Da(s)

3.9.1.1 In response to an action to enforce the standards set forth in 40 CFR Part 60, Subpart Da, §60.42Da, §60.43Da, §60.44Da, and §60.45Da, the Source may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by a malfunction, as defined at 40 CFR Part 60, §60.2. Appropriate penalties may be assessed, however, if the Source fails to meet the burden of proving

all of the requirements in the affirmative defense as specified in 40 CFR Part 60, §60.48Da(s)(1) and (2). The affirmative defense shall not be available for claims for injunctive relief (40 CFR Part 60, §60.48Da(s)).

3.9.2 **Reporting requirements**, 40 CFR Part 60, §60.51Da

For all reports required in this condition the Source shall submit the written reports required under 40 CFR Part 60, Subparts Da and A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period (40 CFR Part 60, §60.51Da(j)).

The Source may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under 40 CFR Part 60, §60.51Da(b) and (j). The format of each quarterly electronic report shall be coordinated with the Administrator. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the Source indicating whether compliance with the applicable emissions standards and minimum data requirements of 40 CFR Part 60, Subpart Da was achieved during the reporting period (40 CFR part 60, §60.51Da(k)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart Da.

3.9.2.1 For SO_2, NO_x, PM, and NO_x plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be reported to the Division, as applicable (40 CFR Part 60, §60.51Da(a)).

3.9.2.2 For SO_2 and NO_x the information contained in 40 CFR Part 60, §60.51Da(b)(1) through (9) shall be reported to the Division for each 24-hour period (40 CFR Part 60, §60.51Da(b)).

3.9.2.3 If the minimum quantity of emission data as required by 40 CFR Part 60, §60.49Da is not obtained for any 30 successive boiler operating days, the information in §60.51Da(c)(1) through (5) as obtained under the requirements of §60.48Da(h) shall be reported to the Division for that 30-day period (40 CFR Part 60, §60.51Da(c)).

3.9.2.4 In addition to the applicable requirements in §60.7, the Source shall submit excess emission reports for any Method 9 opacity observation emissions in excess of the requirements of §60.43c(c) from the facility occur during the reporting period and shall maintain records according to the requirements specified in §60.51Da(d)(1) (40 CFR Part 60, §60.51Da(d)).

3.9.2.5 For any periods for which opacity, SO_2, or NO_x emissions data are not available, the Source shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation for the control system and affected

facility before and following the period of data unavailability (40 CFR Part 60, §60.51Da(f)).

3.9.2.6 The Source shall submit a signed statement indicating whether (40 CFR Part 60, §60.51Da(h)):

a. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified (40 CFR Part 60, §60.51Da(h)(1)).

b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of 40 CFR Part 60, Subpart Da and is representative of plant performance (40 CFR Part 60, §60.51Da(h)(2)).

c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable (40 CFR Part 60, §60.51Da(h)(3)).

d. Compliance with the standards has or has not been achieved during the reporting period (40 CFR Part 60, §60.51Da(h)(4)).

3.9.2.7 For the purposes of the reports required under 40 CFR Part 60, §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter (40 CFR Part 60, §60.51Da(i)).

3.9.3 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

3.10 Colorado Regulation No. 23, Regional Haze

3.10.1 Craig Unit 3 will close no later than December 31, 2029 (Colorado Regulation No. 23, Section IV.F.1.f.).

3.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

3.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

3.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

3.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

3.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

3.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

3.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

3.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 3 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

3.13 Compliance Assurance Monitoring (CAM)

Unit 3 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM and PM_{10} limitations in Condition 3.1, the SO_2 limitations in Condition 3.2, and the NO_x limitations in Condition 3.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendices H, K, and M.

4. B001, B002, and B003 – Units 1, 2, and 3: Natural Gas, Propane, and Fuel Oil

The Source must maintain records of annual usage of natural gas, propane, and fuel oil, and the associated annual heat contents of each, as appropriate. If, for each boiler, the total annual heat content of these fuels combined exceeds 5% of the total heat content of all fuels combusted, this Operating Permit shall be reopened to incorporate the appropriate applicable requirements for combusting combined/alternative fuels.

5. 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Units 1, 2 and 3 are subject to the requirements of MACT UUUUU, also known as the mercury and air toxics (MATS) rule. The applicable requirements under the MATS rule are as follows. The requirements apply to Units 1, 2, and 3 unless otherwise specified.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart UUUUU published in the Federal Register on September 9, 2020. However, if revisions to this Subpart are published at a later date, the Source is subject to the applicable revised requirements.

As of the date of publication of this Operating Permit, Units 1, 2, and 3 all: comply with the low EGU emitter (LEE) requirements for PM; use SO_2 as a surrogate for HCl emissions and use an SO_2 CEMS; Units 1 and 2 use mercury (Hg) CEMS, and Unit 3 uses Hg sorbent traps to monitor compliance with the Hg emission limitations.

5.1 §63.9991 What emission limitations, work practice standards and operating limits must I meet?

5.1.1 At all times, the Source shall meet each emission limit and work practice standard in Table 1 through 3 of 40 CFR Part 63, Subpart UUUUU, as applicable, except as provided under §63.10009, and shall meet each operating limit in Table 4 of Subpart UUUUU, as applicable (40 CFR Part 63, §63.9991(a)(1) and (2)). These requirements are as follows:

5.1.2 The Source is subject to the following requirements from Table 2 of Subpart UUUUU:

Table 2.1 Requirements	Pollutant	Emission limits and work practice standards	Specific requirements for test methods in Table 5 of Subpart UUUUU
a.	Filterable PM	0.03 lb/MMBtu OR 0.3 lb/MWh (gross output)	Collect minimum of 1 dscm per run.
b.	Sulfur dioxide (SO_2)[1]	0.2 lb/MMBtu OR 1.5 lb/MWh	SO_2 CEMS
c.	Mercury (Hg)	1.2 lb/TBtu OR 0.013 lb/GWh	LEE testing for 30 days with a sampling period consistent with that given in 5.2.1 of Appendix A to Subpart UUUUU per Method 30B at Appendix A-8 to 40 CFR Part 60 run or HG CEMS or sorbent trap monitoring system only.

Table 5 - Subpart UUUUU Table 2 Requirements

5.1.3 The Source shall conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, as specified in §63.10021(e) (40 CFR part 63, Table 3.1).

5.1.4 The following work practice standards are required during startup (40 CFR Part 63, Table 3.3):

5.1.4.1 Note: The following two definitions of startup apply to this condition, as applicable (40 CFR Part 63, §63.10042):

a. Either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup; or

b. The period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

5.1.4.2 The Source has the option of complying using either of the following work practice standards (40 CFR Part 63, Table 3.3.a):

a. If the Source chooses to comply using paragraph (1) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, the Source must use clean fuels as defined in §63.10042 for ignition. Once the Source converts to firing coal, residual oil, or solid oil-derived fuel, the Source must engage all of the applicable control technologies except dry scrubber and SCR. The Source must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The Source must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this Subpart UUUUU. The Source must keep records during startup periods. The Source must provide reports concerning activities and startup periods, as specified in §63.10011(g) and §63.10021(h) and (i) (Conditions 5.8.8 and 5.8.9). If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.a(1)).

b. If the Source chooses to comply using paragraph (2) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. The Source shall also collect appropriate data, and shall calculate the pollutant emission rate for each hour of startup. For startup of an EGU, the Source shall use one or a combination of the clean fuels defined in §63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. The Source shall have sufficient clean fuel capacity to engage and operate the PM control device within one hour of adding coal to the unit. The Source shall meet the startup period work practice requirements as identified in §63.10020(e) (Condition 5.7.5). Once the Source stats firing coal, emissions shall be vented to the main stack(s). The Source shall comply with the applicable emission limits beginning with the hour after startup ends. The Source shall engage and operate the PM control(s) within 1 hour of first firing of coal. The Source shall start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than Subpart UUUUU that require operation of the control devices (40 CFR Part 63, Table 3.3.a(2)).

5.1.4.3 If the Source chooses to use just one set of sorbent traps to demonstrate compliance with the applicable emission limit, the Source shall comply with the limit at all times except for startup and shutdown periods (40 CFR Part 63, Table 3.3.c).

5.1.4.4 The Source shall collect monitoring data during startup periods as specified in §63.10020(a) and (e) (Condition 5.7.1 and 5.7.5). The Source shall keep records during startup periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). The Source shall provide reports concerning activities and startup periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.d).

5.1.5 The following work practice standards are required during shutdown (40 CFR Part 63, Table 3.4):

5.1.5.1 The Source shall operate all continuous monitoring systems (CMS) during shutdown. The Source shall collect appropriate data, and shall calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used.

5.1.5.2 While firing coal, the Source shall vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, the Source shall operate the controls when necessary to comply with other standards made applicable to the EGU

by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices.

5.1.5.3 If, in addition to the fuel used prior to the initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel shall be one or a combination of the clean fuels defined in §63.10042 and shall be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.

5.1.5.4 The Source shall comply with all applicable emission limits at all times except during startup and shutdown periods at which time the Source shall meet the requirements of the work practices described in Conditions 5.1.4 and 5.1.5. The Source shall collect monitoring data during shutdown periods, as specified in §63.10020(a) (Condition 5.7.1). The Source shall keep records during shutdown periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. The Source shall provide reports concerning activities and shutdown periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i) (Condition 5.12.9).

5.1.6 As provided in 40 CFR Part 63, §63.6(g), the Administrator may approve the use of an alternative to the work practice standards required in §63.9991 (Condition 5.1) (40 CFR Part 63, §63.9991).

5.2 **§63.10000 What are my general requirements for complying with this subpart?**

5.2.1 The Source shall be in compliance with the emission limits and operating limits in Subpart UUUUU. These limits apply at all times except during periods of startup and shutdown; however the Source is required to meet the work practice requirements, items 3 and 4, in Table 3 of Subpart UUUUU (Conditions 5.1.4 and 5.1.5) during periods of startup or shutdown (40 CFR Part 63, §63.10000(a)).

5.2.2 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include but is not limited to monitoring results, review of operation and maintenance procedure, review of operation and maintenance records, and inspection of the source (40 CFR Part 63,§63.10000(b)).

5.2.3 Initial performance testing is required for all pollutants to demonstrate compliance with the applicable emission limits (40 CFR Part 63, §63.10000(c)(1)).

5.2.3.1 The Source may conduct initial performance testing in accordance with §63.10005(h) (Condition 5.3.6) to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs §63.10000(c)(1)(i)(A) and (B) (Conditions 5.2.3.1.a. and b.) (40 CFR Part 63, §63.10000(c)(1)(i)).

a. Except as provided in §63.10000(c)(1)(i)(c) (Condition 5.2.3.1.c.), the Source may not pursue the LEE option if the EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device (40 CFR Part 63, §63.10000(c)(1)(i)(A)).

b. The Source may not pursue the LEE option for Hg if the EGU is new (40 CFR Part 63, §63.10000(c)(1)(i)(B)).

c. The Source may pursue the LEE option provided that (40 CFR Part 63, §63.10000(c)(1)(i)(c)):

(i) The EGU's control device bypass emissions are measured in the bypass stack or duct, or the control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event (40 CFR Part 63, §63.10000(c)(1)(i)(c)(1)); or

(ii) Except for hours during which only clean fuel is combusted, the Source bypasses the EGU control device only during emergency periods for no more than a total of 2 percent (%) of the EGU's annual operating hours; the Source uses clean fuels to the maximum extent possible during an emergency period; and the Source prepares and submits a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. The Source shall include these emergency emissions along with performance test results in assessing whether the EGU maintains LEE status (40 CFR Part 63, §63.10000(c)(1)(i)(c)(2)).

5.2.3.2 For a qualifying LEE for Hg emissions limits, the Source shall conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(ii)).

5.2.3.3 For a qualifying LEE of any other applicable emissions limits, the Source shall conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(iii)).

5.2.3.4 If the EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, the Source shall demonstrate compliance through an initial performance test and shall monitor continuous performance through either the use of a PM continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly (40 CFR Part 63, §63.10000(c)(1)(iv)).

5.2.3.5 If the EGU does not qualify as a LEE for hydrogen chloride (HCl), the Source may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B of Subpart UUUUU. As an

alternative to HCl CEMS, the Source may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If the EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), the Source may apply a second alternative to HCl CEMS by installing and operating a SO_2 CEMS installed an operated in accordance with 40 CFR part 75 to demonstrate compliance with the applicable SO_2 emission limit (40 CFR Part 63, §63.10000(c)(1)(v)).

5.2.3.6 If the EGU does not qualify as a LEE for Hg, the Source shall demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with Appendix A of Subpart UUUUU (40 CFR Part 63, §63.10000(c)(1)(vi)).

a. The Source may choose to use separate sorbent trap monitoring systems to comply with Subpart UUUUU: one sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown, and the other sorbent trap monitoring system to report average mercury concentration during startup periods or shutdown periods (40 CFR Part 63, §63.10000(c)(1)(vi)(A)).

b. The Source may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emission limit at all times (including startup and shutdown periods) and to report average mercury concentration. The Source shall follow the startup or shutdown requirements that follow and are described in Table 3 of Subpart UUUUU (Conditions 5.1.3, 5.1.4, and 5.1.5) (40 CFR Part 63, §63.10000(c)(1)(vi)(B)).

5.2.4 If the Source demonstrates compliance with any applicable emissions limit through use of a CMS, where a CMS includes CPMS and CEMS, the Source shall develop a site-specific monitoring plan and submit it, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies if the Source elects to petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plants that apply to CEMS and CPMS prepared under Appendix B to 40 CFR Part 60 or Part 75, and that meet the requirements of §63.10010 (Condition 5.6). Using the process described in §63.8(f)(4), the Source may request approval of monitoring system quality assurance and quality control procedures to those specified in this condition and, if approved, include those in the site-specific monitoring plan. The monitoring plan shall address the provisions in §63.10000(d)(2) through (5) (40 CFR Part 63, §63.10000(d)(1)).

5.2.5 As part of the demonstration of continuous compliance, the Source shall perform periodic tune-ups of the EGU according to §63.00021(e) (Condition 5.8.4) (40 CFR Part 63, §63.10000(e)).

5.2.6 Except as provided in §63.10000(n) (Condition 5.2.16), the Source shall be subject to the requirements of Subpart UUUUU for at least 6 months following the last date it met the definition of an EGU subject to the Subpart (e.g., 6 months after a cogeneration unit provided

more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). The Source may opt to remain subject to the provisions of Subpart UUUUU beyond 6 months after the last date it met the definition of an EGU subject to the Subpart (40 CFR Part 63, §63.10000(f)).

5.2.7 Except as provided under §63.10000(n) (Condition 5.2.16), if the unit no longer meets the definition of an EGU subject to Subpart UUUUU the Source must be in compliance with any newly applicable standards on the date which it is no longer subject to the Subpart. The date the Source is no longer subject to the Subpart is a date selected by the source, that must be at least 6 months from the date the that unit last meet the definition of an EGU subject to the Subpart. The Source shall remain in compliance with Subpart UUUUU until the date it selected to cease complying with the Subpart (40 CFR Part 63, §63.10000(g)).

5.2.8 If the Source owns or operates an EGU that does not meet the definition of an EGU subject to Subpart UUUUU on April 16, 2015, and the Source commences or recommences operations that causes the Source to meet the definition of an EGU subject to Subpart UUUUU, the Source is subject to the provisions of Subpart UUUUU, including, but not limited to, the emission limitations and the monitoring requirements as of the first day the Source meets the definition of an EGU subject to Subpart UUUUU. The Source shall complete all initial compliance demonstrations for Subpart UUUUU applicable to the EGU within 180 days after commencing or recommencing operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU (40 CFR Part 63, §63.10000(h)(1)).

5.2.9 The Source shall provide 30 days prior notice of the date it intends to commence or recommence operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU. The notification must include the information in §63.10000(h)(2)(i) through (iv) (40 CFR Part 63, §63.10000(h)(2)).

5.2.10 If the EGU ceases to operate in a manner that causes the unit to meet the definition of an EGU subject to Subpart UUUUU, the Source must be in compliance with any newly applicable Clean Air Act (CAA) section 112 or 129 standards on the date the Source selected consistent with §63.10000(g) and (n) (Condition 5.2.7 and 5.2.16) (40 CFR Part 63, §63.10000(i)(1)).

5.2.11 The Source shall provide 30 days prior notice of the date the EGU will cease complying with Subpart UUUUU. The notification shall identify the content described in §63.10000(i)(2)(i) through (iv) (40 CFR Part 63, §63.10000(i)(2)).

5.2.12 All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart (40 CFR Part 63, §63.10000(j)).

5.2.13 All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU

shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart. All calibration and drift checks shall be performed as of the date the Source ceases to be or becomes subject to the Subpart. The Source shall also comply with provisions §63.10010, §63.10020, and §63.10021 of Subpart UUUUU (Conditions 5.6, 5.7, and 5.8). Relative accuracy tests shall be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under Subpart UUUUU (40 CFR Part 63, §63.10000(k)).

5.2.14 On or before the date an EGU is subject to Subpart UUUUU, the Source shall install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods (40 CFR Part 63, §63.10000(l)).

5.2.15 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (see note in Condition 5.1.4), on or before the date the EGU is subject to Subpart UUUUU, the Source shall install, verify, operate, maintain, and quality assurance each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10000(m)).

5.2.15.1 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system (40 CFR Part 63, §63.10000(m)(1)).

5.2.15.2 The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup and shutdown periods (40 CFR Part 63, §63.10000(m)(2)).

5.2.16 If the Source has permanently converted the EGU from coal or oil to natural gas or biomass after the compliance date (or, if applicable, after the approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents the Source from operating in a manner that would subject the Source to Subpart UUUUU, the Source shall no longer be subject to Subpart UUUUU, notwithstanding the coal or oil usage in the previous calendar years. The date on which the Source is no longer subject to Subpart UUUUU is the date on which the Source converted to natural gas or biomass firing; it is also the date on which the Source must be in compliance with any newly applicable standards (40 CFR Part 63, §63.10000(n)).

5.3 **§63.10006 When must I conduct subsequent performance tests or tune-ups?**

5.3.1 For affected units meeting the LEE requirements of §63.10005(h), the Source must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 of Subpart UUUUU and §63.10007 (Condition 5.4). Should subsequent emissions testing results show the

unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur (40 CFR Part 63, §63.10006(b)):

5.3.1.1 For all pollutant emission limits except for Hg, the Source shall conduct emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(b)(1)).

5.3.1.2 For Hg, the Source shall install, certify, maintain, and operate a Hg CEMS or sorbent trap monitoring system in accordance with Appendix A to Subpart UUUUU, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the Source shall conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1). The Source must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status (40 CFR Part 63, §63.10006(b)(2)).

5.3.2 Except where §63.10006(a) or (b) (Condition 5.3.1) apply, or where the Source installs, certifies, and operates a PM CEMS to demonstrate compliance with a filterable PM emissions limit, the Source shall conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 of Subpart UUUUU, §63.10007, and §63.10000(c) (Conditions 5.4 and 5.2.3), except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(c)).

5.3.3 Except where §63.10006(b) (Condition 5.3.1) applies, for coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, the Source shall conduct all applicable periodic HCl emissions tests according to Table 5 of Subpart UUUUU and §63.10007 (Conditions 5.4) at least quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(d)).

5.3.4 **[Time between performance tests]**

5.3.4.1 Notwithstanding the provisions of §63.10021(d)(1) (Condition 5.8.4.1), the requirements listed in §63.10006 (h) (Condition 5.3.6), and the requirements of §63.10006(f)(3) (Condition 5.3.4.3), the Source shall complete performance tests for the EGU as follows (40 CFR Part 63, §63.10006(f)(1)):

a. At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter (40 CFR Part 63, §63.10006(f)(1)(i));

b. For annual testing (40 CFR Part 63, §63.10006(f)(1)(ii)):

(i) At least 320 calendar days, measured from the test's end date, must separate performance tests (40 CFR Part 63, §63.10006(f)(1)(ii)(A));

(ii) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(B));

(iii) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90 boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(c)); and

c. At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years (40 CFR Part 63, §63.10006(f)(1)(iii)).

5.3.4.2 For units demonstrating compliance through quarterly emission testing, the Source must conduct a performance test in the 4th quarter of a calendar year of the EGU has skipped performance tests in the first 3 quarters of the calendar year (40 CFR Part 63, §63.10006(f)(2)).

5.3.4.3 If the EGU misses a performance test deadline due to being inoperative and if 169 or more boiler operating hours occur in the next test period, the Source must complete an additional performance test in that period as follows (40 CFR Part 63, §63.10006(f)(3)):

a. At least 15 calendar days must separate two performance tests conducted in the same quarter (40 CFR Part 63, §63.10006(f)(3)(i)).

b. At least 107 calendar days must separate two performance tests conducted in the same calendar year (40 CFR Part 63, §63.10006(f)(3)(ii)).

c. At least 350 calendar days must separate two performance tests conducted in the same 3 year period (40 CFR Part 63, §63.10006(f)(3)(iii)).

5.3.5 If the Source elects to demonstrate compliance using emissions averaging under §63.10009 (Condition 5.5), the Source must continue to conduct performance stack tests at the appropriate frequency given in §63.10006(c) through (f) (Conditions 5.3.2 through 5.3.4) (40 CFR Part 63, §63.10009(g)).

5.3.6 If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if the Source chooses to reapply for LEE status, the Source must conduct performance tests at the appropriate frequency given in §63.10006(c) through (e) (Conditions 5.3.2 through 5.3.3) for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria (40 CFR Part 63, §63.10006(h)).

5.3.7 The Source shall conduct a performance tune-up according to §63.10021(e) (Condition 5.8.5) (40 CFR Part 63, §63.10006(i)).

5.3.7.1 For EGUs not employing a neural network combustion optimization during normal operation, each performance tune-up specified in §63.10021(e) must be no more than 36 calendar months after the previous performance tune-up (40 CFR Part 63, §63.10006(i)(1)).

5.4 **§63.10007 What methods and other procedures must I use for the performance tests?**

5.4.1 Except as otherwise provided in §63.10007 (Condition 5.4), the Source shall conduct all required performance tests according to §63.7(d), (e), (f), and (h). The Source must also

develop a site-specific test plan according to the requirements in §63.7(c) (40 CFR Part 63, §63.10007(a)).

5.4.1.1 If a CEMS is used (for Hg, HCl, SO_2, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, the Source shall collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 of Subpart UUUUU), except as otherwise provided in §63.10020(b) (Condition 5.7.2). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §63.10000(c)(1)(vi)(B) and §63.10005(a)(2)(iii) (Condition 5.2.3.6.b) (40 CFR Part 63, §63.10007(a)(1)).

5.4.1.2 If the Source conducts performance testing with test methods in lieu of continuous monitoring, the Source shall operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will generally be between 90 and 110 percent design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(2)).

5.4.1.3 For establishing operating limits with PM CPMS to demonstrate compliance with a PM or non-Hg metals emissions limit, the Source shall operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will generally be between 90 and 110 percent of design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(3)).

5.4.2 The Source shall conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements of Table 5 of Subpart UUUUU (40 CFR Part 63, §63.10007(b)).

5.4.3 If the Source chooses the filterable PM method to comply with the PM emission limit and demonstrates continuous compliance using a PM CPMS as provided for in §63.10000(c) (Condition 5.2.3), the Source must also establish an operating limit according to §63.10011(b), §63.10023 (Condition 5.10), and Tables 4 and 6 of Subpart UUUUU. Should the Source desire to have operating limits that correspond to loads other than maximum normal operating load, the Source must conduct testing at those other loads to determine the additional operating limits (40 CFR Part 63, §63.10007(c)).

5.4.4 Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, the Source shall conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run shall comply with the minimum applicable sampling time or volume specified in Table 2 of Subpart UUUUU (Condition 5.1). Sections §63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or

sorbent trap monitoring systems, and for conducting emission tests for LEE qualification (40 CFR Part 63, §63.10007(d)).

5.4.5 To use the results of performance testing to determine compliance with the applicable emission limits in Table 2 of Subpart UUUUU (Condition 5.1), the Source shall follow the requirements in §63.10007(e)(1) through (3) (40 CFR Part 63, §63.10007(e)).

5.4.6 If the Source elects to (or is required to) use CEMS to continuously monitor Hg, HCl, HF, SO_2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). Default values for diluents cap values and for default gross output are described in §63.10007(f)(1) and (2). For the purposes of Subpart UUUUU, the default values are not considered to be substitute data (40 CFR Part 63, §63.10007(f)).

5.4.7 Upon request, the Source shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of §63.10007 (Condition 5.4) (40 CFR Part 63, §63.10007(g))

5.5 **§63.10009 May I use emissions averaging to comply with this Subpart?**

5.5.1 **[General eligibility]** The Source may use emissions averaging as described in §63.10009(a)(2) (Condition 5.5.2) as an alternative to meeting the requirements of §63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if (40 CFR Part 63, §63.10009(a)(1)):

5.5.1.1 The Source has more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control) (40 CFR Part 63, §63.10009(a)(1)(i)); and

5.5.1.2 The Source uses CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance (40 CFR Part 63, §63.10009(a)(1)(ii)).

5.5.2 The Source may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if the averaged Hg emissions for EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory are equal to or less than 1.2 lb/TBtu or 1.3E-2 lb/GWh on a 30-boiler operating day basis or if the averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30-group boiler operating days (rolling daily) using data from CEMS and sorbent trap monitoring (for Hg), or a combination of data from CEMS and emissions testing (for other pollutants). The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh) from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90-

group boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of data from CEMS and sorbent trap monitoring. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions averaging group operates on each of the 30 or 90 days. The Source must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) of the preceding 30- (or 90-) group boiler operating days (40 CFR Part 63, §63.10009(a)(2)).

5.5.2.1 The Source may choose to have the EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant) (40 CFR Part 63, §63.10009(a)(2)(i)).

5.5.2.2 The Source may not mix bases within the EGU emissions averaging group (40 CFR Part 63, §63.10009(a)(2)(ii)).

5.5.2.3 The Source may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see §63.10009(m) (Condition 5.5.14)) (40 CFR Part 63, §63.10009(a)(2)(iii)).

5.5.3 **[Equations]** The Source must use the following equations when performing calculations for the EGU emissions averaging group (40 CFR Part 63, §63.10009(b)):

5.5.3.1 Group eligibility equations (40 CFR Part 63, §63.10009(b)(1))

$$WAER_m = \frac{(\sum_{j=1}^{p} Herm_j * Rmm_j) + \sum_{k=1}^{m} Ter_k * Rmt_k}{(\sum_{j=1}^{p} Rmm_j) + \sum_{k=1}^{m} Rmt_k} \quad \text{Eq. 1a}$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = Hourly emission rate (e.g., lb/MMBtu, lb/Mwh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = Number of EGUs in emissions averaging group that rely on CEMS,

Ter_k = Emissions rate (lb/MMBtu or lb/MWh) as determined during the initial compliance determination for EGU k,

Rmt_k = Maximum rated heat input, MMbtu/h, or maximum rated gross output, MWh/h, for EGU k, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum[(\sum_{j=1}^{p} Herm_j)*Smm_j*Cfm_j)]+\sum_{k=1}^{m} Ter_k*Smt_k*Cft_k}{\sum(\sum_{j=1}^{p} Smm_j*Cfm_j)+\sum_{k=1}^{m} Smt_k*Cft_k}$$ Eq. 1b

Where:

Smm_j = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU j,

Smt_k = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

5.5.3.2 Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use Equation 2a or 2b of §63.10009(b)(2) to calculate the 30 day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(2)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{p}(Her_i*Rm_i))_p+\sum_{i=1}^{m}(Ter_i*Rt_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p+\sum_{i=1}^{m} Rt_i}$$ Eq. 2a

Where:

Her_i = Hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = Number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n= Number of hours that hourly rates are collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = Number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p + \sum_{i=1}^{m}(Ter_i * St_i * Cft_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p + \sum_{i=1}^{m} St_i * Cft_i}$$ Eq. 2b

Where:

Sm_i = Steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = Steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit I that uses emissions testing.

5.5.3.3 Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory. Use equation 3a or 3b of §63.10009(b)(3) to calculate the 90-day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(3)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Rm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p}$$ Eq. 3a

Where:

Her_i = Hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = Number of EGUs in emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p}$$ Eq. 3b

Where:

Her_I = Hourly emission rate from unit I's Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Sm_i = Steam generation in units of pounds from unit i that uses CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

p = Number of EGUs in the emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

5.5.4 **[Separate stack requirements]** For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, the Source may average filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to Subpart UUUUU if the Source satisfies the requirements in §63.10009(d) through (j) (Conditions 5.5.5 through 5.5.11) (40 CFR Part 63, §63.10009(c)).

5.5.5 For each existing EGU in the averaging group (40 CFR Part 63, §63.10009(d)):

5.5.5.1 The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 190 days after April 16, 2015, or the date on which emissions testing done to support the emissions averaging plan is complete (if the Administrator does not require submission and approval of the emissions averaging plan), or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(1)); or

5.5.5.2 The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(2)).

5.5.6 The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 of Subpart UUUUU at all times following the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(e)).

5.5.7 **[Emissions averaging group eligibility demonstration]** The Source must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to §63.10009(f)(1) and (2) (Conditions 5.5.7.1 and 5.5.7.2) using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing the emissions averaging plan, the Source must conduct required emissions monitoring for 30- (or 90-) days of boiler operating and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with §63.10009. If, before the start of the initial compliance demonstration, the Administrator becomes aware

that the Source intends to use emissions averaging for that demonstration, or if the initial Notification of Compliance Status (NOCS) indicates that the Source intends to implement emissions averaging at a future date, the Administrator may require the Source to submit the proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of the plan, the Source may not being using emissions averaging until the Administrator approves the plan (40 CFR Part 63, §63.10009(f)).

5.5.7.1 The Source must use Equation 1a in §63.10009(b) (Condition 5.5.3.1) to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(1)).

5.5.7.2 If the Source is not capable of monitoring heat input or gross output, and the EGU generates steam for purposed other than generating electricity, the Source may use Equation 1b of §63.10009 (Condition 5.5.3.1) as an alternative to using Equation 1a of §63.10009 to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(2)).

5.5.8 The Source must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to §63.10009(g)(1) and (2) (Conditions 5.5.8.1 and 5.5.8.2). The First averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(g)).

5.5.8.1 The Source must use Equation 2a or 3a of §63.10009(b) (Condition 5.5.3) to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(1)).

5.5.8.2 If the Source is not capable of monitoring heat input or gross output, the Source may use Equation 2b or 3b of §63.10009(b) (Condition 5.5.3) as an alternative to using Equation 2a of §63.10009(b) to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(2)).

5.5.9 **[CEMS (or sorbent trap monitoring use)]** If an EGU in the emissions averaging group using CEMS (or sorbent trap monitoring for Hg emissions) to demonstrate compliance, the Source must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(h)).

5.5.10 **[Emissions testing]** If the Source uses manual emissions testing to demonstrate compliance for one or more EGUs in the emissions averaging group, the Source must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. the Source may use CEMS or sorbent trap data in combination with data from the most recent manual

performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(i)).

5.5.11 **[Emissions averaging plan]** The Source must develop an implementation plan for emissions averaging according to the procedures and requirements in §63.10009(j)(1) and (2) (40 CFR Part 63, §63.10009(j)).

5.5.12 **[Common stack requirements]** For a group of two or more existing affected units, each of which vents through a single common stack, the Source may average emissions to demonstrate compliance with the limits in Table 2 of Subpart UUUUU if the Source satisfies the requirements of §63.10009(l) or (m) (Conditions 5.5.13 or 5.5.14) (40 CFR Part 63, §63.10009(k)).

5.5.13 For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, the Source may treat such averaging group as a single existing unit for purposes of Subpart UUUUU and comply with the requirements of Subpart UUUUU as if the group were a single unit (40 CFR Part 63, §63.10009(l)).

5.5.14 For all other groups of units subject to §63.10009(k) (Condition 5.5.12), the Source may elect to conduct manual performance tests according to procedures specified in §63.10007 (Condition 5.4) in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, the Source must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, the Source may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. The Source may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis (40 CFR Part 63, §63.10009(m)).

5.5.15 **[Combination requirements]** The common stack of a group of two or more existing EGUs in the same subcategory subject to §63.10009(k) (Condition 5.5.12) may be treated as a single stack for purposes of §63.10009(c) (Condition 5.5.4) and included in an emissions averaging group subject to §63.10009(c) (40 CFR Part 63, §63.10009(n)).

5.6 **§63.10010 What are my monitoring, installation, operation, and maintenance requirements?**

5.6.1 Flue gases from the affected units under Subpart UUUUU exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configurations, or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under Subpart UUUUU, the CMS installation requirements for these exhaust configuration are described in §63.10010(a)(1) through (6) (40 CFR Part 63, §63.10010(a)).

5.6.2 If an oxygen (O_2) or carbon dioxide (CO_2) CEMS is used to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. The Source shall install, certify, maintain, and operate the CEMS according to 40 CFR Part 75. Only QA O_2 or CO_2 data in the emissions calculations shall be used; Part 75 substitute data values shall not be used (40 CFR Part 63, §63.10010(b)).

5.6.3 If the Source is required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain the monitoring system and conduct on-going QA testing of the system according to 40 CFR Part 75. The Source shall only use unadjusted, QA flow rate data in the emissions calculations. The Source shall not apply bias adjustment factors to the flow rate data and shall not use substitute flow rate data in the calculations (40 CFR Part 63, §63.10010(c)).

5.6.4 If the Source is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain a moisture monitoring system in accordance with 40 CFR Part 75. Alternatively, for coal-fired units, the Source may use appropriate fuel-specific default moisture values from 40 CFR Part 75, §75.11(b) to estimate the moisture content of the stack gas. If the Source installs and operates a moisture monitoring system, the Source shall not use substitute moisture data in the emissions calculations (40 CFR Part 63, §63.10010(d)).

5.6.5 If the Source uses an HCl and/or HF CEMS, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix B of Subpart UUUUU. The Source shall calculate and record a 30-boiler operating day rolling average HCl or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of Appendix B to Subpart UUUUU) (40 CFR Part 63, §63.10010(e)).

5.6.6 If the Source uses an SO_2 CEMS:

5.6.6.1 The Source shall install the monitor at the outlet of the EGU, downstream of all emission control devices, and the Source shall certify, operated, and maintain the CEMS according to 40 CFR Part 75 (40 CFR Part 63, §63.10010(f)(1)).

5.6.6.2 For on-going QA, the SO_2 CEMS shall meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of Appendix B to 40 CFR Part 75, with the following addition: the Source shall perform the linearity checks required in section 2.2 of Appendix B of 40 CFR Part 75 if the SO_2 CEMS has a span value of 30 ppm or less (40 CFR Part 63, §63.10010(f)(2)).

5.6.6.3 The Source shall calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day.

Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO_2 emission rates in the 30-boiler operating day period (40 CFR Part 63, §63.10010(f)(3)).

5.6.6.4 The Source shall use only unadjusted, QA SO_2 concentration values in the emission calculations; the Source shall not apply bias adjustment factors to the Part 75 O_2 data and shall not use Part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default gross output and the diluents cap are available for use in the hourly SO_2 emission rate calculations, as described in §63.10007(f) (Condition 5.4.6). The Source shall use a flag to identify each startup or shutdown hour and report a special code if the diluents cap or default gross output is used to calculate the SO_2 emission rate for any of these hours (40 CFR Part 63, §63.10010(f)(4)).

5.6.7 If the Source uses and Hg CEMS or a sorbent trap monitoring system, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix A of Subpart UUUUU. The Source shall calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to Section 6.2 of Appendix A of Subpart UUUUU, is the average of all the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of Appendix A of Subpart UUUUU explains how to reduce sorbent trap monitoring system data to an hourly basis (40 CFR Part 63, §63.10010(g)).

5.6.8 If the Source uses a PM CPMS to demonstrate continuous compliance with an operating limit, the Source shall install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in §63.10010(h)(1) through (7) (40 CFR Part 63, §63.10010(h)).

5.6.9 If the Source chooses to comply with the PM filterable emission limit in lieu of metal HAP limits, the Source may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in §63.10010(i)(1) through (5). The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10010(i)).

5.6.10 The Source may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with §63.7(f) as an alternative to the performance test method specified in Subpart UUUUU. If approved to use a HAP metals CEMS, the compliance limit shall be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU. If approved, the Source may choose to install, certify, operated, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in §63.10010(j)(1) through (5) (40 CFR Part 63, §63.10010(j)).

5.6.11 If the Source chooses to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source must install, verify, operate, maintain, and QA each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice

standards required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10010(l)).

5.6.11.1 The Source shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods (40 CFR Part 63, §63.10010(l)(1)).

5.6.11.2 The Source shall submit the site-specific monitoring plan upon request by the Administrator (40 CFR Part 63, §63.10010(l)(2)).

5.6.11.3 The provisions of the monitoring plan must address the items in §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(3)).

5.6.11.4 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications to address §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(4)).

5.6.11.5 The Source shall operate and maintain the monitoring system according to the site-specific monitoring plan (40 CFR Part 63, §63.10010(l)(5)).

5.7 §63.10020 How do I monitor and collect data to demonstrate continuous compliance?

5.7.1 The Source must monitor and collect data according to §63.10020 and the site-specific monitoring plan required by §63.10000(d) (Condition 5.2.4) (40 CFR Part 63, §63.10020(a)).

5.7.2 The Source must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in the site-specific monitoring plan. The Source is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable (40 CFR Part 63, §63.10020(b)).

5.7.3 The Source may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §63.10000(c)(1)(vi)(B) (Condition 5.2.3.6b) and §63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system QA or QC activities may not be used in calculations used to report emissions or operating levels. The Source shall use all of the QA data collected during all other periods in assessing the operation of the control device and associated control system (40 CFR Part 63, §63.10020(c)).

5.7.4 Periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities excluding zero and span checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with

monitoring system malfunctions or monitoring system out-of-control periods is a deviation from the monitoring requirements (40 CFR Part 63, §63.10020(d)).

5.7.5 If the Source elects to reply on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (40 CFR Part 63, §63.10020(e)):

5.7.5.1 During each period of startup, the Source shall record the information in §63.10020(e)(1)(i) through (v) (40 CFR Part 63, §63.10020(e)(1)).

5.7.5.2 During each period of shutdown, the Source shall record the information in §63.10020(e)(2)(i) through (v) (40 CFR Part 63, §63.10020(e)(2)).

5.7.5.3 For PM or non-mercury HAP metals work practice monitoring during startup periods, the Source shall monitor and collect data according to §63.10020(e)(3)(i)(A) through (E) and the site-specific monitoring plan required by §63.10010(l) (Condition 5.6.11) (40 CFR Part 63, §63.10020(e)(3)).

5.8 §63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

5.8.1 The Source shall demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 2 through 4 of Subpart UUUUU, according to the monitoring specified in Tables 6 and 7 of Subpart UUUUU and §63.10021(b) through (g) (40 CFR Part 63, §63.10021(a)).

5.8.2 Except as otherwise provided in §63.10020(c) (Condition 5.7.3), if the Source chooses to use a CEMS to measure SO_2, PM, HCl, HF, or Hg, emissions, or using a sorbent trap monitoring system to measure Hg emissions, the Source must demonstrate continuous compliance by using all QA hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 8 of Subpart UUUUU (below) to determine the 30- (or, if applicable, 90-) boiler operating day rolling average (40 CFR Part 63, §63.10021(b)).

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \qquad \text{Eq. 8}$$

Where: Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

5.8.3 If the Source uses PM CPMS data to measure compliance with an operating limit in Table 4 of Subpart UUUUU, the Source must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. The Source shall demonstrate continuous compliance by using all QA hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30-operating day

rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 9 of Subpart UUUUU (below) to determine the 30-boiler operating day average (40 CFR Part 63, §63.10021(c)).

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \quad \text{Eq. 9}$$

Where: Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30-boiler operating days.

5.8.4 If the Source uses quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10021(d)), the Source

5.8.4.1 May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year (40 CFR Part 63, §63.10021(d)(1)).

5.8.4.2 Must conduct the performance test as defined in Table 5 of Subpart UUUUU and calculate the results of the testing in units of the applicable emissions standard (40 CFR Part 63, §63.10021(d)(2)); and

5.8.5 The Source shall conduct periodic performance tune-ups of the EGU, as specified in §63.10021(e)(1) through (9). For the first tune-up, the Source may perform the burner inspection any time prior to the tune-up or may delay the first burner inspection until the next schedule EGU outage provided the Source meets the requirements of §63.10005. Subsequently, the Source shall perform an inspection of the burner at least once every 48 calendar months. If the EGU is offline when a deadline to perform the tune-up passes, the Source shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit (40 CFR Part 63, §63.10021(e)).

5.8.6 The Source must submit the applicable reports and notifications required under 40 CFR 63.10031(a) through (k) (Condition 5.12) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS Client Tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS Client Tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved (40 CFR Part 63, §63.10021(f)).

5.8.7 The Source shall report each instance in which it did not meet an applicable emissions limit or operating limit in Tables 2 through 4 of Subpart UUUUU or failed to conduct a required tune-

up. These instances are deviations from the requirements of Subpart UUUUU. These deviations shall be reported according to §63.10031 (Condition 5.12) (40 CFR Part 63, §63.10021(g)).

5.8.8 The Source shall follow the startup or shutdown requirements as given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10021(h)).

5.8.8.1 The Source may use the diluents cap and default gross output values, as described in §63.10007(f) (Condition 5.4.6), during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(1)).

5.8.8.2 The Source shall operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(2)).

5.8.8.3 The Source may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in §63.10011(g)(4). Until promulgation in the Federal Register of the final alternative non-opacity emission standard, the Source shall comply with paragraph (1) of the definition of "startup" in §63.10042 (40 CFR Part 63, §63.10021(h)(4)).

5.8.9 If you are on paragraph 2 of the definition of startup in 40 CFR 63.10042, the Source must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in the semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, the Source must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i) (40 CFR Part 63, §63.10021(i)).

5.9 §63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

5.9.1 Following the compliance date, the Source must demonstrate compliance with Subpart UUUUU on a continuous basis by meeting the requirements of §63.10022(a)(1) through (4), as follows (40 CFR Part 63, §63.10022(a)).

5.9.1.1 For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.10009(f) and (g) (Conditions 5.5.7and 5.5.8) (40 CFR Part 63, §63.10022(a)(1));

5.9.1.2 For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test (40 CFR Part 63, §63.10022(a)(2));

5.9.1.3 For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 of

Subpart UUUUU that applies (40 CFR Part 63, §63.10022(a)(3)).

5.9.1.4 For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10022(a)(4)).

5.9.2 Any instance where the Source fails to comply with the continuous monitoring requirements in §63.10022(a)(1) through (3) (Conditions 5.9.1.1 through 5.9.1.3) is a deviation (40 CFR Part 63, §63.10022(b)).

5.10 **§63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?**

5.10.1 During the initial performance test or any such subsequent performance test that demonstrates compliance with filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 2, the Source shall record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs) (40 CFR Part 63, §63.10023(a)).

5.10.2 The Source shall determine the operating limit as provided in §63.10023(b)(1) and (2). The Source shall verify an existing or establish a new operating limit after each repeated performance test (40 CFR Part 63, §63.10023(b)).

5.10.2.1 The Source shall determine the operating limit according to the requirements of §63.10023(b)(i) through (vi)) (40 CFR Part 63, §63.10023(b)(2)).

5.10.3 The Source shall operate and maintain the process and equipment such that the 30 operating day average PM CMPS output does not exceed the operating limit determined in §63.10023(a) and (b) (40 CFR Part 63, §63.10023(c)).

5.11 **§63.10030 What notifications must I submit and when?**

5.11.1 The Source shall submit all of the notifications in §63.7(b) and (c), §63.8(e), (f)(4) and (6), and §63.9(b) through (h) that apply by the dates specified (40 CFR Part 63, §63.10030(a)).

5.11.2 As specified in §63.9(b)(2), if the Source commences startup on an affected EGU before April 16, 2012, the Source shall submit an Initial Notification not later than 120 days after April 16, 2012 (40 CFR Part 63, §63.10030(b)).

5.11.3 When the Source is required to conduct a performance test, the Source shall submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin (40 CFR Part 63, §63.10030(d)).

5.11.4 When the Source is required to conduct an initial compliance demonstration as specified in §63.10011(a), the Source shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report shall contain all the information specified in §63.10030(e)(1) through (8), as applicable (40 CFR Part 63, §63.10030(e)).

5.11.5 The Source shall submit the notifications in §63.10000(h)(2) and (i)(2) (Conditions 5.2.8 and 5.2.10) that may apply by the dates specified (40 CFR Part 63, §63.10030(f)).

5.12 **§63.10031 What reports must I submit and when?**

5.12.1 The source must submit each report in §63.10031(a)(1) through (5) that applies (40 CFR Part 63, §63.10031(a)).

5.12.2 The source must submit semiannual compliance reports according to the requirements in §63.10031(b)(1) through (6) (40 CFR Part 63, §63.10031(b)).

5.12.3 The compliance report shall contain the information required in §63.10031(c)(1) through (10) (40 CFR Part 63, §63.10031(c)).

5.12.4 Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in §63.10031(c) (Condition 5.12.3) must include the excess emissions and monitor downtime summary report described in 40 CFR §63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR §63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and the Source must, instead, include in the quarterly compliance reports described in paragraph §63.10031(g) (Condition 5.12.7) the applicable data elements in section 13 of Appendix E of Subpart UUUUU for any "deviation" (as defined in 40 CFR §63.10042 and elsewhere in Subpart UUUUU) that occurred during the calendar quarter. If there were no deviations, the Source must include a statement to that effect in the quarterly compliance report (40 CFR Part 63, §63.10031(d)).

5.12.5 Each affected source that has obtained a Title V Operating Permit pursuant to 40 CFR Part 70 or Part 71 must report all deviations as defined in Subpart UUUUU in the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A). If an affected source submits a semiannual compliance report pursuant to §63.10031(c) and (d) (Condition 5.12.3 and 5.12.4), or two quarterly compliance reports covering the appropriate calendar half pursuant to §63.10031(g) (Condition 5.12.7), along with, or as part of, the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A), and the compliance report(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in Subpart UUUUU, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority (40 CFR Part 63, §63.10031(e)).

5.12.6 For each performance stack test completed prior to January 1, 2024, (including 30- (or 90-) boiler operating day Hg LEE demonstration tests and PM tests to establish operating limits for PM CPMS), the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR §63.10031(g)

(Condition 5.12.7), the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU along with the quarterly compliance report for the calendar quarter in which the test was completed (40 CFR Part 63, §63.10031(f)).

5.12.6.1 For each RATA of an Hg, HCl, HF, or SO_2 monitoring system completed prior to January 1, 2024, and for each PM CEMS correlation test, each relative response audit (RRA) and each response correlation audit (RCA) of a PM CEMS completed prior to that date, the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the test is completed. For each SO_2 or Hg RATA completed on or after January 1, 2024, the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E of Subpart UUUUU prior to or concurrent with the relevant quarterly emissions report. For HCl or HF RATAs, and for correlation tests, RRAs, and RCAs of PM CEMS that are completed on or after January 1, 2024, the Source must submit the appendix E reference method information together with the summarized electronic test results, in accordance with section 11.4 of Appendix B of Subpart UUUUU or section 7.2.4 of Appendix C of Subpart UUUUU, as applicable (40 CFR Part 63, §63.10031(f)(1)).

5.12.6.2 If, for a particular EGU or a group of EGUs serving a common stack, the Source has elected to demonstrate compliance using a PM CEMS, an approved HAP metals CEMS, or a PM CPMS, the Source must submit quarterly PDF reports in accordance with §63.10031(f)(6) (Condition 5.12.6.5), which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7). In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CEMS, the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7) must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO_2, if the Source has elected to (or are required to) continuously monitor these pollutants. Further, if the EGU or common stack is in an averaging plan, the quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group (40 CFR Part 63, §63.10031(f)(2)).

5.12.6.3 The Source must submit semiannual compliance reports as required under §63.10031(b) through (d) (Conditions 5.12.2 through 5.12.4), ending with a report covering the semiannual period from July 1 through December 31, 2023, and Notifications of Compliance Status as required under §63.10030(e) (Condition

5.12.5), as PDF files. Quarterly compliance reports shall be submitted in XML format thereafter, in accordance with §63.10031(g) (Condition 5.12.7), starting with a report covering the first calendar quarter of 2024 (40 CFR Part 63, §63.10031(f)(4)).

5.12.6.4 All reports required by Subpart UUUUU not subject to the requirements in §63.10031(f) and (f)(1) through (4) (Conditions 5.12.6 through 5.12.6.3) shall be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the Source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to §63.10031(f) and (f)(1) through (4) in paper format (40 CFR Part 63, §63.10031(f)(5)).

5.12.6.5 All reports and notifications described in §63.10031(f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA in the specified format and at the specified frequency, using the ECMPS Client Tool. Each PDF version of a stack test report, CEMS RATA report, PM CEMS correlation test report, RRA report, and RCA report must include sufficient information to assess compliance and to demonstrate that the reference method testing was done properly. Note that EPA will continue to accept, as necessary, PDF reports that are being phased out at the end of 2023, if the submission deadlines for those reports extend beyond December 31, 2023. The data elements in §63.10031(f)(6)(i) through (xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file (40 CFR Part 63, §63.10031(f)(6)).

5.12.7 Starting with a report for the first calendar quarter of 2024, the Source must use the ECMPS Client Tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of Appendix E to Subpart UUUUU. For each stack test summarized in the compliance report, the Source must also submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter. (40 CFR Part 63, §63.10031(g)).

5.12.8 On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR §63.9(h)(2)(ii), as PDF files, using the ECMPS Client Tool. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each Notification (40 CFR Part 63, §63.10031(h)).

5.12.9 If the Source has have elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown incidents that occur on or prior to December 31, 2023, the Source must include the information in 40 CFR §63.10031(c)(5) in the semiannual compliance report, in a PDF file. If the Source has elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, the Source must use the ECMPS Client Tool to submit the information in 40 CFR §63.10031(c)(5) and 40 CFR §63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each startup and shutdown report (40 CFR Part 63, §63.10031(i)).

5.12.10 If the Source elects to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with Subpart UUUUU and have begun recording valid data from the PM CEMS prior to November 9, 2020, the Source must use the ECMPS Client Tool to submit a detailed report of the PS 11 correlation test (see Appendix B to 40 CFR Part 63) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, the Source must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, the Source must submit the PDF report according to section 7.2.4 of Appendix C to Subpart UUUUU. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(j)).

5.12.11 If the Source elects to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, the Source must submit quarterly reports of the QA/QC activities (*e.g.,* calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CEMS is used for the compliance demonstration in that quarter. Otherwise, the Source must submit a report for the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(k)).

5.13 **§63.10032 What records must I keep?**

5.13.1 The Source must keep records according to §63.10032(a)(1) and (2). If the Source is required to (or elects to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if the Source elects to use a PM CPMS, the Source must keep the records required under Appendix A and/or Appendix B and/or Appendix C and/or Appendix D to Subpart UUUUU. If the Source elects to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, the source must keep records of the applicable data elements under 40 CFR §63.7(g). The Source must also keep records of all data elements and other information in Appendix E to Subpart UUUUU that apply to the compliance strategy (40 CFR Part 63, §63.10032(a)).

5.13.1.1 In accordance with 40 CFR §63.10(b)(2)(xiv), a copy of each notification or report that the Source submits to comply with this Subpart UUUUU. The Source must also keep records of all supporting documentation for the initial Notifications of Compliance Status, semiannual compliance reports, or quarterly compliance reports that you submit (40 CFR Part 63, §63.10032(a)(1)).

5.13.1.2 Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §63.10(b)(2)(viii) (40 CFR Part 63, §63.10032(a)(2)).

5.13.2 For each CEMS and CPMS, the Source shall keep records according to §63.10032(b)(1) through (4) (40 CFR Part 63, §63.10032(b)).

5.13.2.1 Records as described in §63.10(b)(2)(vi) through (xi) (40 CFR Part 63,

§63.10032(b)(1)).

5.13.2.2 Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3) (40 CFR Part 63, §63.10032(b)(2)).

5.13.2.3 Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i) (40 CFR Part 63, §63.10032(b)(3)).

5.13.2.4 Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period (40 CFR Part 63, §63.10032(b)(4)).

5.13.3 The Source shall keep the records required in Table 7 of Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit, as applicable (40 CFR Part 63, §63.10032(c)).

5.13.4 The Source shall also keep the records in §63.10032(d)(1) through (3) (Conditions 5.13.4.1 through 5.13.4.3) (40 CFR Part 63, §63.10032(d)).

5.13.4.1 The Source shall keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used (40 CFR Part 63, §63.10032(d)(1)).

5.13.4.2 If the Source combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR §241.3(b)(1), the Source shall keep a record which documents how the secondary material meets each of the legitimacy criteria. If the Source combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR §241.3(b)(2), the Source shall keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR §241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under §40 CFR §241.3(c), the Source shall keep a record which documents how the fuel satisfies the requirements of the petition process (40 CFR Part 63, §63.10032(d)(2)).

5.13.4.3 For an EGU that qualifies as a LEE under §63.10005(h), the Source shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions for the pollutant to increase within the last year (40 CFR Part 63, §63.10032(d)(3)).

5.13.5 If the Source elects to average emissions consistent with §63.10009 (Condition 5.5), the Source must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(g), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022 (Condition 5.9) (40 CFR Part 63, §63.10032(e)).

5.13.6 Regarding startup or shutdown periods (40 CFR Part 63, §63.10032(f)):

5.13.6.1 Should the Source choose to rely on paragraph (1) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of the occurrence and duration of each startup or shutdown (40 CFR Part 63, §63.10032(f)(1)).

5.13.6.2 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of (40 CFR Part 63, §63.10032(f)(2)):

a. The determination of the maximum possible clean fuel capacity for the EGU (40 CFR Part 63, §63.10032(f)(2)(i));

b. The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU (40 CFR Part 63, §63.10032(f)(2)(ii));

c. The information required in §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10032(f)(2)(iii)).

5.13.7 The source shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment (40 CFR Part 63, §63.10032(g)).

5.13.8 The Source shall keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b) (Condition 5.2.2), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation (40 CFR Part 63, §63.10032(h)).

5.13.9 The Source shall keep records of the type(s) and amount(s) of fuel used during each startup or shutdown (40 CFR Part 63, §63.10032(i)).

5.13.10 If the Source elects to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, the Source shall keep records of the type(s) and amounts(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met (40 CFR Part 63, §63.10032(j)).

5.14 **§63.10033 In what form and how long must I keep my records?**

5.14.1 Records shall be in a form suitable and readily available for expeditious review, according to §63.10(b)(1) (40 CFR Part 63, §63.10033(a)).

5.14.2 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.10033(b)).

5.14.3 The Source shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The Source may keep the records off site for the remaining 3 years (40 CFR Part 63, §63.10033(c)).

5.15 §63.10040 What parts of the General Provisions apply to me?

5.15.1 Table 9 of Subpart UUUUU shows which parts of the General Provisions in 40 CFR Part 63, §63.1 through §63.15 apply to the Subpart UUUUU affected EGU.

6. P101 – Coal Handling System for Units 1 & 2

The coal handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F101a	Coal hauling – Units 1 & 2	$MgCl_2$ or equivalent application
F101b	Coal unloading to grizzly – Units 1 & 2	Water spray with surfactant
F101c	Coal surge pile	Water with surfactant, as necessary
S101d	Primary coal crushing – Units 1 & 2	Baghouse
S101e	Secondary coal crushing building – Units 1 & 2	Baghouse
S101f	Common coal transfer building belt A	Baghouse
S101g	Common coal transfer building belt B	Baghouse
S101h	Coal stackout building – Units 1 & 2	Baghouse
F101i	Coal stackout – Units 1 & 2	Telescopic chute
F101j	Coal storage piles – Units 1 & 2	Water spray prior to stackout, as necessary
S101k	Coal reclaim A – Units 1 & 2	Baghouse
S101l	Coal reclaim B – Units 1 & 2	Baghouse
S101m	Coal tripper deck & silos – Units 1 & 2	Baghouse

Table 6 - P101 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	6.1	3,900,000 tons/year (through each P101 unit)			Recordkeeping	Annually
PM & PM_{10}	6.2	F101a		AP-42, 13.4.2	Recordkeeping and Calculation	Annually
		F101b S101f S101g S101h F101i S101k S101l S101m		PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton		
		S101d		PM: 0.02 lb/ton PM_{10}: 0.009 lb/ton		
		S101e		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		
		F101c F101j				
Opacity	6.3	Not to exceed 20% opacity except during certain operational activities at			EPA Reference Method 9	Semiannually See Condition 15

		which time not to exceed 30% opacity			
Fugitive Emissions	6.4	See Condition 6.4			
Equipment Operation	6.5	See Condition 6.5			
NSPS Y	6.6	Opacity not to exceed 20%		See Condition 6.6	

Table 7 - P101 Emissions and Requirements Summary

6.1 **Coal consumption must not exceed 3,900,000 tons per year, Colorado Construction Permit 11MF276**

6.1.1 Compliance with the annual limit shall be determined on an annual, calendar year basis. Sixty days after the end of the calendar year, a new annual total is calculated.

6.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Units 1 and 2.

6.1.3 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

6.1.4 Records of coal throughput and belt-scale calibrations must be maintained on site for Division inspection upon request.

6.2 **PM and PM_{10} emissions** shall be calculated using the annual coal throughput, emission factors from Table 7 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

6.2.1 For emissions estimates from units without emission factors in Table 7 (F101a, F101c and F101j), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

6.2.2 The Division has approved a 99.0% emission control efficiency for S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

6.3 **Opacity**

6.3.1 All emission units in this condition, with the exception of the fugitive emission units (F101a, F101b, F101c, F101i, and F101j), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

6.4 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 11MF276, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures shall be used to minimize fugitive particulate emissions:

6.4.1 Water with added surfactant must be applied at the grizzly (truck hopper).

6.4.2 The haul road used by coal trucks on the Craig Station property shall be treated with magnesium chloride (or equivalent) to control dust. The treatment material shall be applied as often as necessary to remain viable as a control measure.

6.4.3 The coal being loaded to live storage will be sprayed with water with added surfactant, on an as-needed basis.

6.4.4 Free fall from the stackout tower to the stockpile will be minimized by utilization of telescoping tubes.

6.4.5 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

6.5 All process equipment must be maintained and operated such that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control systems. The emission control equipment shall be maintained in accordance with the manufacturer's instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF276). This condition applies to emission units S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

6.6 **40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants**

The following emission units are subject to the requirements of NSPS Y: S101d, S101e, S101f, and S101g.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

6.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

6.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

7. P102 – Coal Handling System for Unit 3

P102 may be used at times for blending coal used in Units 1 and 2. The coal handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F102a	Coal train unloading – Unit 3	Water spray
S102b	Coal conveyor portal building – Unit 3	Baghouse
S102c	Coal conveyor portal building – Unit 3	Baghouse
S102d	Secondary coal crushing (2 crushers) – Unit 3	Baghouse
S102e	Coal stackout building – Unit 3	Baghouse
F102f	Coal stackout – Unit 3	Telescopic chutes
F102g	Coal storage pile – Unit 3	PM control plan, including compaction, chemical use or watering, as necessary
S102h	Coal reclaim system – Unit 3	Baghouse
S102i	Coal tripper deck & silos – Unit 3	Baghouse
S102j	Loadout coal to railcars – Unit 3	Baghouse
S102k	Common coal transfer building extension	Baghouse
F102l	Coal train loading	N/A

Table 8 - P102 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	7.1	4,500,000 tons/year (each unit but tripper deck) 1,897,344 tons/year (tripper deck) Coal Storage Pile: ≤ 14.5 acres			Recordkeeping	Monthly
PM & PM_{10}	7.2	F102a S102b S102c S102e F102f S102h S102k S102i S102j	PM: 1.7 tons/year (all units combined) PM_{10}: 0.7 tons/year (all units combined)	PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton	Recordkeeping and Calculation	Monthly
		S102d		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		

		F102g F102l			
Opacity	7.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		EPA Reference Method 9	Semiannually See Condition 15
Fugitive Emissions	7.4	See Condition 6.4			
Required Controls	7.5	See Condition 7.5			
NSPS Y	7.6	Opacity not to exceed 20%		See Condition 7.6	
CAM	7.7	Condition 7.7			

Table 9 - P102 Emissions and Requirements Summary

7.1 **Coal consumption, Colorado Construction Permit 12MF322-2**

Coal throughput must not exceed 4,500,000 tons per year (all units except for tripper deck)

Coal throughput through the tripper deck must not exceed 1,897,344 tons per year

Coal storage pile must not exceed 14.5 acres in size

7.1.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Unit 3. Throughput to the tripper deck must be monitored separately.

7.1.3 Compliance with the coal storage pile limit must be certified on a once per calendar year basis. The Source must provide to the Division the methodology for the measurement. At the Division's discretion, the Division may require an alternative methodology for the measurement.

7.1.4 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

7.1.5 Records of coal throughput, coal storage pile certifications, and belt-scale calibrations must be maintained on site for Division inspection upon request.

7.2 **PM emissions must not exceed 1.7 tons per year, PM_{10} emissions must not exceed 0.7 tons per year, Colorado Construction Permit 12MF322-2**

7.2.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.2.2 Emissions shall be calculated using the annual coal throughput, emission factors from Table 9 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

7.2.3 For emission estimates from units without emission factors in Table 9 (F102g, F102l), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

7.2.4 The Division has approved a 99.0% emission control efficiency for S102b, S102c, S102d, S102e, S102h, S102i, S102j, and S102k. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

7.3 **Opacity**

7.3.1 All emission units in this condition, with the exception of the fugitive emission units (F102a, F102f, F102g, and F102l), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

7.4 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 12MF322-2, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures represent BACT for PM and PM_{10} and must be used to minimize fugitive particulate emissions:

7.4.1 The train dump area must be equipped with water spray bars which shall be operated whenever a load of coal is dumped, as needed, to minimize fugitive dust emissions. The spray nozzles shall be positioned so as to achieve the greatest effectiveness in dust control.

7.4.2 Adjustable chutes must be used to transfer coal to the stockpiles. These chutes shall minimize the free fall distance from the chute outlet to the pile.

7.4.3 Control measures must be taken as necessary to minimize fugitive coal dust emissions from the coal storage pile. These control measures shall include compaction, spraying the piles with water, or if necessary, a chemical stabilizer.

7.4.4 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

7.5 Fabric filter baghouses shall be employed to control dust emissions from crushing operations, transferring operations, and reclaiming of coal (Colorado Construction Permit, 12MF322-2). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

7.6 **40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants**

The following emission units are subject to the requirements of NSPS Y: F102a, S102b, S102c, S102d, S102h, S102j, S102k, and F102l.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

7.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

7.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

7.7 **Compliance Assurance Monitoring (CAM)**

The secondary coal crushing building (S102d) is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 7.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendix I.

8. P201 – Limestone Handling and Storage Facility for Units 1 and 2

The limestone handling and storage facility for Units 1 and 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F201a	Limestone hauling	Paved portions of road
S201b	Limestone truck unloading	Baghouse
S201c	Limestone silo #1 – Units 1 & 2	Baghouse
S201d	Limestone silo #2 – Units 1 & 2	Baghouse
N/A	Limestone conveying	Building enclosure

Table 10 – P201 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Limestone Delivery	8.1				Recordkeeping	Annually
PM & PM_{10}	8.2	F201a		PM: Paved: 3.97 Unpaved: 10.3 PM_{10}: Paved: 0.79 Unpaved: 2.9 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Annual
		S201b S201c S201d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	8.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
Baghouse	8.4	See Condition 8.4				
Equipment Operation	8.5	See Condition 8.5				
NSPS OOO (conveying only)	8.6	Opacity not to exceed 7%				

Table 11 – P201 Emissions and Requirements Summary

8.1 Records of the annual quantity (in tons) of limestone delivered for P201 must be maintained and made available for Division inspection upon request.

8.2 Emissions shall be calculated using the annual limestone throughput (estimated as limestone delivered to the facility), emission factors from Table 11 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

8.2.1 For F201a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 11. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

8.2.2 The Division has approved a 99.0% emission control efficiency for S201b, S201c, and S201d. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

8.3 **Opacity**

8.3.1 All emission units in this condition, with the exception of the fugitive emission units (F201a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

8.4 The unloading facilities (S201b) must be vented to a baghouse (Colorado Construction Permit 11MF415). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

8.5 All process equipment (S201b, S201c, S201d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF415). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

8.6 **40 CFR Part 60, Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants**

The following emission units are subject to the requirements of NSPS OOO: limestone belt conveyors. The applicability date for Subpart OOO was August 31, 1983; any facility which commenced construction, modification, or reconstruction after this date is subject. The Source must maintain a log of

which pieces of the limestone conveying system are subject to each of the following provisions of NSPS OOO for Division inspection upon request.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart OOO published in the Federal Register on April 28, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

8.6.1 If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in §60.672(a) and (b), or the building enclosing the affected facility or facilities must comply with the following emission limit (40 CFR Part 60, §60.672(e)):

8.6.1.1 Fugitive emissions from the building openings (except for vents as defined in §60.671) must not exceed 7 percent opacity (40 CFR Part 60, §60.672(e)(1)).

8.6.2 The Source must submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in in §60.672 of Subpart OOO, including reports of opacity observations made using Method 9 to demonstrate compliance with §60.672(b) and (e) (Condition 8.6.1) (40 CFR Part 60, §60.676(f)).

8.6.3 The conveyors subject to Subpart OOO in this condition are also subject to the provisions of 40 CFR Part 60, Subpart A, General Provisions as described in Condition 18.

9. P202 – Lime Handling and Storage Facility for Unit 3

The lime handling and storage facility for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F202a	Lime hauling	Paved portions of road
S202b	Lime unloading	Baghouse
S202c	Lime conveying and silo	Baghouse
S202d	Lime day bin	Baghouse

Table 12 – P202 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Lime Delivery	9.1	28,000 tons/year via truck 28,000 tons/year via rail			Recordkeeping	Monthly
PM & PM_{10}	9.2	F202a	PM: 14.9 tons/year, 12-month rolling total (all units combined) PM_{10}: 2.9 tons/year, 12-month rolling total (all units combined)	PM: Paved: 5.39 Unpaved: 11.84 PM_{10}: Paved: 1.08 Unpaved: 3.37 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Monthly
		S202b S202c S202d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	9.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-4 Baghouses	9.4	See Condition 9.4				
Equipment Operation	9.4.3	See Condition 9.4.3				

Table 13 – P202 Emissions and Requirements Summary

9.1 **Throughput of lime must not exceed 28,000 tons per year via truck, and 28,000 tons per year via rail (Colorado Construction Permit 12MF322-4)**

9.1.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data

9.1.2 Monthly records of the quantity (in tons) of lime throughput for P202 must be maintained and made available for Division inspection upon request. These records must specify whether the lime was delivered via truck or via rail.

9.2 **PM and PM_{10} emissions must not exceed 14.9 tons per year and 2.9 tons per year, respectively, for all P202 emission units combined (Colorado Construction Permit 12MF322-4)**

9.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

9.2.2 Emissions shall be calculated using the actual lime throughput (as required in Condition 9.1), emission factors from Table 13 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

9.2.3 For F202a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 13. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

9.2.4 The Division has approved a 99.0% emission control efficiency for S202b, S202c, and S202d, and a 90% emission control efficiency for F202a. The acceptance of these control efficiencies is contingent on continued routine maintenance of and operation procedures performed on the control devices in accordance with manufacture's specifications and good engineering practices. These procedures and maintenance schedules shall be maintained on site and provided for Division inspection upon request.

9.3 **Opacity**

9.3.1 All emission units in this condition, with the exception of the fugitive emission units (F202a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

9.4 **Colorado Construction Permit 12MF322-4**

9.4.1 The bulk lime unloading facilities (S202b) must be vented to a baghouse. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.2 The lime silo must be vented to a fabric filter baghouse to control emissions from unloading and working losses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.3 All process equipment (S202b, S202c, S202d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 12MF322-4). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

10. P203 – Ash Handling System for Units 1 & 2

The ash handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S203a	Ash storage silo A – Units 1 & 2	Baghouse (Shared with S203e)
S203b	Ash storage silo B – Units 1 & 2	Baghouse (Shared with S203d)
F203c	Ash truck loading – Units 1 & 2	Low dust unloader
S203d	Silo B dry ash unloading – Units 1 & 2	Baghouse (Shared with S203b)
S203e	Silo A dry ash unloading – Units 1 & 2	Baghouse (Shared with S203a)

Table 14 – P203 Emission Units Description

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Ash Processed	10.1			Recordkeeping	Annually
PM & PM_{10}	10.2	S203a S203e S203b S203d	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Annually
		F203c	PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton		
Opacity	10.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
11MF332 Process Requirements	10.4	See Condition 10.4			

Table 15 – P203 Emissions and Requirements Summary

10.1 Records of the estimated quantity (in tons) of ash processed for P203 must be maintained and made available for Division inspection upon request. Ash quantities are estimated from the number of trucks loaded and the average truck load capacity (Colorado Regulation No. 3, Part C, Section V.C.5.).

10.2 Emissions shall be calculated using the annual ash throughput, emission factors from Table 15 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

10.2.1 The Division has approved a 99.0% emission control efficiency for S203a and S203b. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

10.3 **Opacity**

10.3.1 All emission units in this condition, with the exception of the fugitive emission units (F203c) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

10.4 **Colorado Construction Permit 11MF332** (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

10.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

10.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 10.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

10.4.3 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

10.4.3.1 Ash for disposal must be loaded through chutes into the trucks. Ash leaving the chutes and loaded into trucks for disposal must be sufficiently wet to minimize fugitive dust emissions.

10.4.3.2 Deposition of mud and dirt on improved public streets and roads must be prevented, as necessary, to control fugitive dust emissions.

10.4.4 All process equipment (S203a, S203b, S203d, S203e) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

11. P204 – Ash Handling System for Unit 3

The ash handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S204a	Ash storage silo C – Unit 3	Baghouse
F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3	Low dust loader (wet ash) Baghouse (Only for dry fly ash loading)
S204c	Recycle ash tank	Baghouse
F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3	$MgCl_2$ application on roads

Table 16 – P204 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Ash Throughput	11.1	Unit 3 flyash handling: 174,649 tons/year Unit 3 ash and scrubber sludge handling: 237,247 tons/year			Recordkeeping	Monthly
PM & PM_{10}	11.2	S204a S204c	PM: 76.6 tons/year (all units combined) PM_{10}: 16.1 tons/year (all units combined)	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Monthly
		F204b		Flyash loading: PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton Dry ash unloading: PM: 0.081 lb/ton PM_{10}: 0.039 lb/ton From AP-42, 13.2.4 Assume: U = 8.1 mph, M = 0.25%	
		F204d		PM: Paved: 6.39 Unpaved: 12.76 PM_{10}: Paved: 1.28		

				Unpaved: 3.6 EF in lb per vehicle mile traveled		
Opacity	11.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-3 Process Requirements	11.4	See Condition 11.4				

Table 17 – P204 Emissions and Requirements Summary

11.1 **Unit 3 flyash handling must not exceed 174,649 tons per year, Unit 3 ash and scrubber sludge handling must not exceed 237,247 tons per year, Colorado Construction Permit 12MF322-3**

11.1.1 Compliance with the annual throughput limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.1.2 Records of the quantity (in tons) of Unit 3 flyash handled and Unit 3 ash and scrubber sludge handled must be maintained and made available for Division inspection upon request.

11.2 **PM emissions must not exceed 76.6 tons per year, PM_{10} emissions must not exceed 16.1 tons per year, Colorado Construction Permit 12MF322-3**

11.2.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.2.2 Emissions shall be calculated using the annual ash throughputs, emission factors from Table 17 (AP-42, Section 13.2.4 (November 2006), note that F204b includes emission factors for both flyash loading and dry ash unloading), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

11.2.3 For emission estimates from units which reference AP-42, Section 13.4.2 (November, 2006) in Table 17, records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

11.2.4 The Division has approved a 99.0% emission control efficiency for S204a and S204c, a 90.0% emission control efficiency for F204d ash haul road, and 80% and 99% emission control efficiencies for F204b wet flyash loading, and F204b dry ash loading, respectively. The acceptance of these control efficiencies shall only be granted provided that the Source operates

and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

11.3 **Opacity**

11.3.1 All emission units in this condition, with the exception of the fugitive emission units (F204b ash truck loading, and F204d ash haul road) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

11.4 **Colorado Construction Permit 12MF322-3** (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

11.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

11.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 11.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

11.4.3 **Fugitive Emissions –** The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

11.4.3.1 Ash loaded into trucks for disposal must be sufficiently wet to control fugitive dust emissions.

11.4.3.2 A low dust unloading system must be employed to load the ash hauling trucks for ash disposal. Ash leaving these unloaders must be sufficiently wet to minimize fugitive emissions.

11.4.3.3 All components of the ash conveying system must be dust tight to eliminate leaks in the system.

11.4.3.4 The scrubber sludge and ash haul road for Units 1, 2, and 3 must be treated with magnesium chloride ($MgCl_2$), or equivalent, as a dust suppressant. The $MgCl_2$ must be applied in accordance as necessary in accordance with good air pollution control practices to minimize the emission of fugitive dust.

11.4.4 All process equipment must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

12. S401 & S402 – Units 1 & 2 Cooling Towers

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	12.1	Maximum Pumping Capacity: 180,000 gallons/minute (per tower)		Design Limitation Certification	Annually
Total Dissolved Solids	12.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	12.3	PM: 27.2 tons/year PM_{10}: 27.2 tons/year	TDS Sampling See Condition 12.3	Recordkeeping and Calculation	Annually
VOC	12.4	5.0 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Annually
Opacity	12.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 12.5	

Table 18 – S401 & S402 Emissions and Requirements Summary

12.1 **The cooling tower water flow rate must not exceed 180,000 gallons per minute (per tower), Colorado Construction Permit 96MF195**

12.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system (153,000 gallons per minute). The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

12.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

12.2 **Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 96MF195**

12.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

12.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division-approved test method.

12.2.2.1 Monthly samples must be taken at least seven (7) days apart.

12.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration shall be the average of all samples taken, as appropriate.

12.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 12.2), and results must be maintained and made available for Division inspection upon request.

12.3 **PM and PM_{10} emissions must not exceed 27.2 tons per year (combined emissions), Colorado Construction Permit 96MF195**

12.3.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

12.4 **VOC emissions must not exceed 5.0 tons per year (combined emissions), Colorado Construction Permit 96MF195**

12.4.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 18 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

12.5 **Opacity**

12.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as

records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

13. S403 – Unit 3 Cooling Tower

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	13.1	Maximum Pumping Capacity: 180,000 gallons/minute		Design Limitation Certification	Annually
Total Dissolved Solids	13.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	13.2.2	PM: 13.6 tons/year PM_{10}: 13.6 tons/year	TDS Sampling See Condition 13.2.2	Recordkeeping and Calculation	Monthly
VOC	13.4	2.5 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Monthly
Opacity	13.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 13.5	

Table 19 – S403 Emissions and Requirements Summary

13.1 **The cooling tower water flow rate must not exceed 180,000 gallons per minute, Colorado Construction Permit 98MF0141**

13.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system. The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

13.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

13.2 **Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 98MF0141**

13.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

13.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division approved test method.

13.2.2.1 Monthly samples must be taken at least seven (7) days apart.

13.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration shall

be the average of all samples taken, as appropriate.

13.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 13.2), and results must be maintained and made available for Division inspection upon request.

13.3 **PM and PM_{10} emissions must not exceed 13.6 tons per year, Colorado Construction Permit 98MF0141**

13.3.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

13.4 **VOC emissions must not exceed 2.5 tons per year, Colorado Construction Permit 98MF0141**

13.4.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 19 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

13.5 **Opacity**

13.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance

procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

14. Emergency Diesel Engines

The emergency fire-pump engine, Units 1 & 2 emergency diesel generator engine, and the Unit 3 emergency diesel generator engine (see Table 1 for relevant make, model, and serial numbers) are emission units covered under this condition. At the time of issuance of this Operating Permit, these engines do not require emission limits because they are exempt under Colorado Regulation No. 3, Part C, Section II.E.3.nnn.(iii) since they have fewer than five (5) tons per year of actual emissions.

14.1 Except as provided in Condition 14.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity (Colorado Regulation No. 1, II.A.1.).

14.1.1 An EPA Reference Method 9 opacity observation shall be performed on this engine at least once per calendar year of operation when the engine is operating during conditions suitable for properly performing a valid Method 9 observation. If an engine has not been operated or if a valid Method 9 observation could not be performed when the engine did operate during the calendar year, the Source is not required to operate the engine for the sole purpose of obtaining an annual opacity observation.

14.1.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.1.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.1.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observation. These records and the copy of the certification shall be made available to the Division for review upon request.

14.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any pollutant resulting from start-up, which is in excess of 30% opacity for a period or period aggregated more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, II.A.4.).

14.2.1 A record shall be kept of the type, date, and time of the commencement and completion of each and every condition subject to Regulation No. 1, II.A.4. that results in an opacity exceedance. The records shall be made available to the Division upon request for review. A Method 9 observation shall be performed any time an engine start-up requires longer than ten (10) consecutive minutes.

14.2.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.2.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.2.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observations. The records and the copy of the certification shall be made available for to the Division upon request for review.

14.3 **40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [Federal-only requirement]**

The emergency diesel fire pump engine in the insignificant activities list is subject to the requirements in 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines."

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart ZZZZ published in the Federal Register on 2/27/2014. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63, Subpart ZZZZ.

The D.C. Circuit Court issued a mandate on May 4, 2016 for vacatur for certain requirements of allowing emergency engines to operate for limited hours for demand response. See EPA memorandum "Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines" published on April 15, 2016 for more information.

These requirements have not been adopted into Colorado Regulation no. 8, Part E as of the date of publication of this Operating Permit, and are therefore not state-enforceable. In the event that these requirements are adopted into Colorado Regulations, they will become state-enforceable.

14.3.1 Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions do not have to meet the requirements of Subpart ZZZ and of 40 CFR Part 63, Subpart A, including initial notification requirements (40 CFR Part 63, §63.6590(b)(3)(iv)). Under Subpart ZZZZ, the definition of a limited use stationary RICE means any stationary RICE that operates less than 100 hours per year (40 CFR Part 63, §63.6675). *Note that the Units 1&2, and the Unit 3 emergency engines may qualify for this exemption. The Source must maintain records which demonstrate that the annual hours of operation for each engine are under 100 if claiming this exemption.*

§63.6602 – What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

14.3.2 If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you (40 CFR Part 63, §63.6602). The applicable requirements of Table 2c are as follows:

14.3.2.1 Change oil and filter every 500 hours of operation or annually, whichever comes first. The Source has the option to utilize an oil analysis program as described in §63.6625(i) to extend the specified oil change requirement.

14.3.2.2 Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

14.3.2.3 Inspect all hoses and belts every 500 hours of operation, or annually, whichever comes first, and replace as necessary.

14.3.2.4 During periods of startup the Source must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

§63.6605 – What are my general requirements for complying with this Subpart?

14.3.3 The Source shall be in compliance with the operating limitations and other requirements in Subpart ZZZZ that apply at all times (40 CFR Part 63, §63.6605(a)).

14.3.4 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the Source to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspections of the Source (40 CFR Part 63, §63.6605(b)).

§63.6625 – What are my monitoring, installation, collection, operation, and maintenance requirements?

14.3.5 The Source shall operate and maintain the engines according to the manufacturer's emission-related written instructions. Alternatively the Source shall develop a separate maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, §63.6625(e)(2)).

14.3.6 The Source shall install a non-resettable hour meter on each engine if not already installed (40 CFR Part 63, §63.6625(f)).

§63.6640 – How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

14.3.7 The Source shall demonstrate continuous compliance with each operating limitation, and other requirements in Tables 1a, 1b, 2a, 2b, 2c, and 2d of Subpart ZZZZ, as applicable, according to methods specified in Table 6 of Subpart ZZZZ, which are described as follows (40 CFR Part 63, §63.6640(a)):

14.3.7.1 For demonstrating compliance with work or management practices (40 CFR Part 63, Table 6, (9)(a)):

a. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions (40 CFR Part 63, Table 6, (9)(a)(i)); or

b. Develop and follow an alternative maintenance plan which must provide to the extent practicable for the maintenance and operation to the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, Table 6, (9)(a)(ii)).

14.3.8 The Source shall operate the engine according to the requirements in §63.6640(f)(1) through (4) (Conditions 14.3.8.1 through 14.3.8.2) for the engine to be considered emergency engine under Subpart ZZZZ. Any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in §63.6640(f)(1) through (4), is prohibited. If the Source does not operate the engine according to the requirements in §63.6640(f)(1) through (4), the engine will not be considered an emergency engine under Subpart ZZZZ and must meet all requirements for non-emergency engines (40 CFR Part 63, §63.6640(f)).

14.3.8.1 There is no time limit on the use of emergency stationary RICE in emergency situations (40 CFR Part 63, §63.6640(f)(1)).

14.3.8.2 The Source may operate the engine for the purposes specified in §63.6640(f)(2)(i) (Condition 14.3.8.2.a) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by §63.6640(f)(3) and (4) counts as part of the 100 hours per calendar year allowed by §63.6640(f)(2) (40 CFR Part 63, §63.6640(f)(2)).

a. Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator

maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year (40 CFR Part 63, §63.6640(f)(2)(i)).

§63.6655 – What records must I keep?

14.3.9 The Source shall keep records of the maintenance conducted on the engine to demonstrate that it was operated and maintained according to the maintenance plan (40 CFR Part 63, §63.6655(e)).

14.3.10 The Source shall keep records of the hours of operation of the engine as recorded on the non-resettable hour meter. The owner or operator shall document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation (40 CFR Part 63, §63.6655(f)).

§63.6660 – In what form and how long must I keep my records?

14.3.11 The records shall be in a form suitable and readily available for expeditious review according to §63.10(b)(1) (40 CFR Part 63, §63.6660(a)).

14.3.12 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.6660(b)).

14.3.13 The Source shall keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1) (40 CFR Part 63, §63.6660(c)).

§63.6665 – What parts of the General Provisions apply to me?

14.3.14 The engine is subject to the General Provisions of 40 CFR Part 63, Subpart A as are outlined in Table 8 of Subpart ZZZZ. These requirements include but are not limited to (40 CFR Part 63, §63.6665):

14.3.14.1 No owner or operator must operate any affected source in violation of the requirements of 40 CFR Part 63 (§63.4(a)(1)); and

14.3.14.2 No owner or operator shall fail to keep records, notify, report, or revise reports as required under 40 CFR Part 63 (§63.4(a)(2)).

15. Colorado Regulation No. 1, Section II – Opacity

These limits apply to the following emission units which reference this condition throughout the Operating Permit:

P101 – Coal Handling System for Units 1 & 2, not including fugitive sources (F101a, F101b, F101c, F101i, and F101j) (Condition 6)

P102 – Coal Handling System for Unit 3, not including fugitive sources (F102a, F102f, F102g, and F102l) (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, not including fugitive sources (F201a) (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, not including fugitive sources (F202a) (Condition 9)

P203 – Ash Handling System for Units 1&2, not including fugitive sources (F203c) (Condition 10)

P204 – Ash Handling System for Unit 3, not including fugitive sources (F204b and F204d) (Condition 11)

S401 & S402 – Units 1 & 2 Cooling Towers, compliance is presumed per Condition 12.5.1 (Condition 12)

S403 – Unit 3 Cooling Tower, compliance is presumed per Condition 13.5.1 (Condition 13)

15.1 Except as provided in Condition 15.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference method for visible emissions measurements on which these standards are based is EPA Method 9 (40 CFR Part 60, Appendix A (July. 1992)). (Colorado Regulation No. 1, Section II.A.1) Note: This opacity limit applies at all times including during periods of shutdown and to offline emissions except as specified in Condition 15.2.

15.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity as measured by EPA Method 9 (unless otherwise specified in this permit) for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes. (Colorado Regulation No. 1, II.A.4)

15.3 Unless specific conditions in this permit require otherwise, monitoring for sources subject to Condition 15 shall be performed as follows.

15.3.1 A U.S. EPA Reference Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A, as adopted by reference in Colorado Regulation No. 6, Part A) shall be

performed at least semiannually. If any such observation indicates an exceedance of the applicable limit, additional observations must be performed. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken the shows the opacity is less than the opacity limit. All Method 9 readings shall be conducted by a certified observer.

15.3.2 Records of the results of U.S. EPA Reference Method 9 readings and a copy of the U.S. EPA Reference Method 9 reader's certification shall be kept on site and made available to the Division for inspection upon request.

15.3.3 Copies of any observations exceeding the applicable standard(s) shall be submitted with the next scheduled semi-annual report.

15.3.4 At all other times, in the absence of credible evidence to the contrary, compliance with the opacity limits shall be assumed, provided the Operating and Maintenance Plan requirements for bagfilters / baghouses set forth in Condition 16 are met, as appropriate.

16. Periodic Monitoring and Operating and Maintenance (O&M) Requirements for Control Devices

These requirements apply to each bagfilter / baghouse and scrubber associated with the following emission units which vent to the control device/s, as appropriate (Colorado Regulation No. 3, Part C, Section V.C.5.):

B001 – Unit 1 Boiler, baghouse and scrubber (Condition 1)

B002 – Unit 2 Boiler, baghouse and scrubber (Condition 2)

B003 – Unit 3 Boiler, baghouse and scrubber (Condition 3)

P101 – Coal Handling System for Units 1 & 2, baghouse (Condition 6)

P102 – Coal Handling System for Unit 3, baghouse (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, baghouse (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, baghouse (Condition 9)

P203 – Ash Handling System for Units 1&2, baghouse (Condition 10)

P204 – Ash Handling System for Unit 3, baghouse (Condition 11)

16.1 Bagfilters / Baghouses

16.1.1 The baghouse shall be equipped with an operable pressure drop measuring device. Pressure drop and/or cycle-time set point shall be used as a parameter for initiating compartment cleaning cycles. Documentation of the manufacturer's recommended operating range shall be maintained and made available to the Division for inspection upon request. Readings that are outside the range shall be cause for investigation. The results of any related maintenance work performed shall be documented in either hardcopy or electronic form and made available to the Division for inspection upon request.

16.1.2 Routine maintenance of and operational procedures performed on the baghouse shall be conducted in accordance with manufacturer's specifications and good engineering practices. These procedures shall be in written format. Any maintenance work performed shall be documented and made available to the Division for inspection upon request.

16.1.3 The baghouse shall be periodically inspected for bag integrity and overall mechanical integrity. At a minimum, these checks will be performed whenever the unit is down for a Planned Maintenance Outage (PMO). In addition, an inspection and any necessary maintenance or repairs shall be made whenever an opacity spike is observed, or if there is reason to suspect a broken bag or other equipment malfunction. For purposes of this requirement, a "spike" is defined as a sudden or gradual increase in opacity that, based on the operator's experience, may indicate a possible control equipment of process problem. Repairs performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of

these inspections, shall be documented and made available to the Division for inspection upon request.

16.1.4 **[Unit 3 Baghouse Only]** The bag leak detector will be operated and maintained in accordance with manufacturer's recommendations and good engineering practices. In the event that the leak detector indicates a leak, the Source will make the necessary repairs to the baghouse as soon as safely practicable. Leaks and their associated repairs will be documented for Division inspection upon request.

16.1.5 All records associated with baghouse O&M requirements must be retained for a minimum of five years.

16.2 Scrubbers

16.2.1 The Source shall perform routine maintenance and inspections of the equipment. The routine maintenance will be based upon operating hours of the scrubber equipment. Repairs or adjustments performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of these inspections, shall be documented and made available to the Division for inspection upon request.

16.2.2 SO_2 readings from the CEMS will be used as an indicator of maintenance needs or operational changes to the scrubber. Repairs or adjustments performed (other than minor adjustments), as well as any repairs done as a result the SO_2 readings, shall be documented and made available to the Division for inspection upon request.

16.2.3 All records associated with scrubber O&M requirements must be retained for a minimum of five years.

17. Particulate Matter Stack Testing

These requirements apply to each PM emission unit in this permit which has been identified as requiring stack testing to demonstrate compliance with an applicable PM emission limit, as appropriate.

17.1 To demonstrate compliance with 40 CFR Part 60, Subpart Da PM emission limits, subsequent performance testing on Unit 3 for filterable PM emissions must be performed within 12 months of the previous performance test in accordance with the schedule outlined in §60.48Da(o), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.2 To demonstrate compliance with 40 CFR Part 63, Subpart UUUUU (MATS) and Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent MATS and Regional Haze performance testing on Units 1 and 2, and subsequent MATS performance testing on Unit 3 for filterable PM emission limits must be performed in accordance with the schedule specified under MATS, in accordance with the requirements of Conditions 1.1, 1.10, 2.1, 2.9.3, 3.1, 3.10, and 5, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3 To demonstrate compliance with the Best Available Control Technology (BACT) PM and PM_{10} filterable and condensable emission limits for Unit 3, performance testing must be performed annually (Colorado Construction Permit 12MF322-1), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3.1 If the results of the performance testing show that the PM and PM_{10} filterable and condensable emissions are less than 75% of the BACT limits, the next performance testing may be performed biennially instead of annually.

17.4 To demonstrate compliance with Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent performance testing on Unit 3 for filterable PM and PM_{10} emissions must be performed in accordance with the requirements and procedures set forth in EPA Test Method 5, and Method 201A, as set forth in 40 CFR Part 60, Appendix A. This performance testing must be performed annually, or in accordance with the following schedule, as applicable:

17.4.1 If any test results indicate emissions are less than or equal to 50% of the emission limit, the subsequent test shall be performed within five (5) years of the date of the test.

17.4.2 If any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, the subsequent test shall be performed within three (3) years of the date of the test.

17.4.3 If any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until either of the above test results are achieved. A performance test must consist of three (3) test runs, with each run at least 120 minutes in duration. Test results must be

converted to the applicable units and compliance with be based on the average of three (3) test runs.

17.5 For all compliance demonstrations in Condition 17:

17.5.1 The test protocol, test, and test report shall be in accordance with the requirements of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/cdphe/air/compliance-enforcement). A compliance testing protocol shall be submitted for Division approval at least thirty (30) calendar days prior to any performance of the test required under this condition.

17.5.2 No compliance test required herein shall be performed without prior written approval of the protocol by the Division.

17.5.3 The Division reserves the right to witness the test. In order to facilitate the Division's ability to make plans to witness the test, notice of the date (s) for the stack test shall be submitted to the Division at least thirty (30) calendar days prior to the test.

17.5.4 The Division may for good cause shown, waive this thirty (30) day notice requirement. In instances when a scheduling conflict is presented, the Division shall immediately contact the permittee in order to explore the possibility of making modifications to the stack test schedule.

17.5.5 The compliance test results shall be submitted to the Division within sixty (60) calendar days of the completion of the test unless a longer period is approved by the Division.

17.5.6 Any stack test conducted to show compliance with an annual emission limitation shall multiply the results of the test (lb/MMBtu) by the annual permitted fuel usage to compare against the limitation.

17.5.7 Results of all tests conducted shall be kept on site and made available to the Division upon request.

17.5.8 The performance testing for filterable PM may be satisfied by the periodic PM testing required by 40 CFR Part 63, Subpart UUUUU (MATS) in accordance with the requirements of Condition 5, as appropriate.

17.6 During each of the Method 5 performance tests conducted on Unit 3 as required by this condition, a baseline opacity limit shall be established for the compliance assurance monitoring (CAM) requirements as specified in Conditions 3.13, and Appendix H. The value of the baseline opacity level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurement recorded during each of the test run intervals conducted for the performance test, and then adding an baseline opacity adjustment factor to the calculated average value for all of the test runs.

17.6.1 The baseline opacity adjustment factors are:

17.6.1.1 5.0% opacity addition to the test run opacity average if the results of the PM performance tests are less than or equal to 50% of the PM standard; or

17.6.1.2 3.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 50%, but less than or equal to 75% of the PM standard; or

17.6.1.3 2.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 75% of the PM standard.

17.6.2 If the calculated opacity value (COMS average plus adjustment factor) is less than 5.0%, then the opacity baseline level is set at 5.0%.

17.6.3 If the baseline opacities established under this condition from any subsequent PM performance test are less than the current baseline opacity levels minus 1%, the Source shall maintain the new baseline opacity used as the indicator range on site for Division inspection upon request.

17.6.4 If the baseline opacities established under this condition from any subsequent PM performance test are greater than or equal to the current baseline opacity level minus 1%, the Source shall maintain records of the new baseline opacity used as the indicator range on site and available for Division inspection upon request.

18. 40 CFR Part 60, Subpart A, General Provisions for New Source Performance Standards

Units subject to an NSPS under 40 CFR Part 60 are subject to the requirements under Subpart A, General Provisions, which include but are not limited to:

B001 – Unit 1 Boiler (Condition 1)

B002 – Unit 2 Boiler (Condition 2)

B003 – Unit 3 Boiler (Condition 3)

P101 – Coal Handling System for Units 1 & 2 – S101d, S101e, S101f, and S101g (Condition 6)

P102 – Coal Handling System for Unit 3 – F102a, S102b, S102c, S102d, S102h, S102j, S102k, and S102l (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2 – limestone belt conveyors (Condition 8)

18.1 At all times, including periods of startup, shutdown, and malfunction owners and operators shall to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source (40 CFR Part 60.11(d), as adopted by reference in Colorado Regulation No. 6, Part A).

18.2 The Source shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility; or any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or device is inoperative (40 CFR Part 60, §60.7(b), as adopted by reference in Colorado Regulation No. 6, Part A).

18.3 No article, machine, equipment or process shall be used to conceal an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gasses discharged into the atmosphere (40 CFR Part 60, §60.12, as adopted by reference in Colorado Regulation No. 6, Part A).

19. Continuous Opacity Monitoring Systems (COMS) and Continuous Emissions Monitoring Systems (CEMS)

The following requirements apply to the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow continuous emission monitoring systems (CEMS), and to the continuous opacity monitoring systems (COMS). Note that these requirements are in addition to those under the Acid Rain Program as set forth in Section III of this permit, those under 40 CFR Part 60, Subparts D and Da – Standards of Performance for Electric Utility Steam Generating Units, those under 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, and those under the Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001).

19.1 CEMS and COMS Quality Assurance and Quality Control (QA/QC) Requirements

19.1.1 Except as provided for below, the **Unit 3 CO CEMS** is subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation and performance specifications of 40 CFR Part 60 Appendix B, Performance Specification 4/4A. This CEMS are subject to the quality assurance/quality control requirements in 40 CFR Part 60, Appendix F and Subpart A, §60.13 and Condition 19.1.8 of this permit.

19.1.1.1 The CO data shall meet the applicable "primary equipment hourly operating requirements" for hourly average calculation methodology specified in 40 CFR Part 75, Subpart B, §75.10(d).

19.1.1.2 Relative accuracy test audit (RATA) frequency will be determined according to 40 CFR Part 60, Appendix F.

19.1.2 The **SO_2, NO_x (and diluent), CO_2, and flow monitors** are subject to the applicable requirements of 40 CFR Part 75. The monitoring systems shall meet the equipment, installation, and performance specification requirements in 40 CFR Part 75, Appendix A. These CEMS shall meet the QA/QC requirements in 40 CFR Part 75, Appendix B and the conversion procedures of Appendix F and Condition 19.1.8 of this permit.

19.1.3 The **Unit 3 stack inlet SO_2 and CO_2 monitors** are subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation, and performance specifications in 40 CFR Part 60, Appendix B, the QA/QC requirements in 40 CFR Part 60, Appendix F, and the conversion procedures of Condition 19.1.8.

19.1.4 The **COMS** are subject to the requirements of 40 CFR Part 75. Each COMS shall meet the design, installation, equipment, and performance specifications in 40 CFR Part 60, Appendix B, Performance Specification 1.

19.1.5 **QA/QC plans** shall be prepared for the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow CEMS in accordance with the requirements of 40 CFR Part 75, Appendix B. These plans shall be made available to the Division upon request. Revisions shall be made to the plans at the request of the Division.

19.1.6 **[Units 1 & 2 COMS]** The Source must follow the QA/QC procedures of 40 CFR Part 60, Subpart A, §60.13(d), and Subpart D, §60.45(c)(3).

19.1.7 **[Unit 3 COMS]** The Source shall follow the QA/QC requirements of 40 CFR Part 60, Subpart A, §60.13(d) and Subpart Da, §60.48Da(o)(2)(ii).

19.1.8 The **SO_2, NO_x, and CO CEMS** are subject to the following requirements:

19.1.8.1 **[Relative Accuracy Test Audits (RATA)]** RATA shall be conducted in the units of the emission limitation (e.g., lb/MMBtu) for all of the emission limitations that are applicable to the emissions unit. The RATA for emissions units that have annual emission limitations (tons/yr) will be conducted in terms of pounds per hour (lb/hr).

19.1.8.2 **[Data Acquisition and Handling System (DAHS)]** The DAHS shall be able to record and manipulate the data in the units of the emission limitation (e.g., lb/MMBtu) and meet the reporting requirements for all of the emissions limitations that are applicable to the emissions unit.

Note at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

19.2 **General Provisions**

19.2.1 The Source shall ensure that all CEMS and COMS required are in operation and monitoring unit emissions or opacity at all times that the associated boiler combusts any fuel, except as follows:

19.2.1.1 During gaseous fuel combustion provided special considerations are met as provided in 40 CFR Part 75, §75.11(e);

19.2.1.2 During the use of an alternative monitoring system as approved by the Administrator pursuant to the requirements in 40 CFR Part 75, Subpart E (see Condition 19.2.2);

19.2.1.3 During periods of calibration, quality assurance, or preventative maintenance performed pursuant to 40 CFR part 75, §75.21 and Appendix B;

19.2.1.4 During periods of repair, periods of backups of data from a data acquisition and handling system or recertification performed pursuant to 40 CFR Part 75, §75.20;

19.2.1.5 The Source shall also ensure, subject to the exceptions noted above, that the COMS required are in operation and monitoring opacity during the time following combustion when fans are still operating, unless fan operation is not required to be included under any other applicable requirement (40 CFR Part 75, §75.10(d)).

19.2.2 Alternative monitoring system, alternative reference method, or any other alternative for the required CEMS shall not be used without having obtained prior written approval from the appropriate agency, either the Division or the U.S. EPA, depending on which agency is authorized to approve such alternative under applicable law. Any alternative CEMS or COMS shall be certified in accordance with the requirements of 40 CFR Parts 60 or 75, as applicable, prior to use.

19.2.3 All test and monitoring equipment, methods, procedures, and reporting shall be subject to the review and approval by the Division, prior to any official use. The Division shall have the right to inspect such equipment, methods, and procedures and data obtained at any time. The Division may provide a witness(es) for any and all tests, at the Division's discretion.

19.2.4 A file shall be maintained of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by applicable portions of 40 CFR Part 60, Subparts A, D, Da, Appendices A, B, and F, and 40 CFR Part 75. This information must be recorded in a permanent form suitable for Division inspection (40 CFR Part 60, §60.7(f)).

19.2.5 Records shall be maintained of the occurrence and duration of any startup, shutdown, or malfunction, or emergency condition (as defined in Subpart Da) in the operation of the source; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative (40 CFR Part 60, §60.7(b)).

19.3 **Data Replacement Requirements**

19.3.1 **[CEMS]** For periods when QA data is not available from the CEMS, the data replacement procedures in 40 CFR Part 75, Subpart D shall be used for determining the total (annual) emissions. For purposes of monitoring compliance with the annual NOx and SO_2 emission limitations (tons/yr), replaced and bias-adjusted data shall be included when assessing compliance with the annual limitations.

Note that CO emissions are not specifically referenced in the Subpart D procedures, the CEMS DAHS is programmed to substitute CO emissions using the same procedures specified for NO_x. Additionally, since CO emissions are not subject to requirements in 40 CFR Part 75, the CO emission data is not required to be bias-adjusted.

19.3.2 **[COMS]** When the COMS is unable to provide QA data in accordance with 40 CFR Part 75 for more than eight (8) consecutive hours, the Source shall utilize either a backup opacity monitor, EPA Reference Method 9, or an "Operating Report During Monitor Unavailability" to satisfy the requirements for periodic monitoring under 40 CFR Part 70 and Colorado Regulation No. 3.

19.3.2.1 If backup monitors are used, the next quarterly report submitted by the Source shall identify the dates and times the backup monitors were in use.

19.3.2.2 If EPA Reference Method 9 observations are used, visual observations in accordance with the reference method shall be taken and recorded by the Source whenever the Source is in operation and while fuel is present in the boiler.

a. When such circumstances exist, the visual observations shall be performed by a certified opacity observer each 24 hour period thereafter over a thirty minute period until the opacity monitoring system is again able to provide QA data.

b. If a visual emissions observation cannot be performed in accordance with EPA Reference Method 9, the Source shall record the reasons why that is the case.

c. Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

19.3.2.3 If an "Operating Report During Monitor Unavailability" is used, the Source shall record the registered opacity monitor reading prior to the monitor unavailability period and that immediately follows such periods. A Source shall also record and maintain a description of a unit operating characteristics that demonstrate the likelihood of compliance with the applicable opacity limitation. Such operating circumstances shall be identified on a unit specific basis and provided to the Division and shall include information related to the operation of the control equipment and any other operational parameters that may affect opacity.

19.4 **Recordkeeping and Reporting Requirements**

19.4.1 The Source shall submit excess emissions and monitoring reports and/or summary reports as required by 40 CFR Part 60, Subpart A, §60.7(c) and (d). The frequency of submittal of such reports shall be quarterly, and such reports shall be submitted to the Division by the 30th day following the end of each calendar quarter. Reports shall consist of the following information for all pollutants monitored for the quarterly period and all applicable limits of this permit:

19.4.1.1 Excess emission reports shall include the following information:

a. The magnitude of excess emissions computed in accordance with §60.13(h) and Division guidelines, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period (40 CFR Part 60, §60.7(c)(1)).

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunctions (if known), the corrective action take or preventative measures adopted (40 CFR Part 60, §60.7(c)(2)).

c. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments (40 CFR part 60, §60.7(c)(3)).

d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report (40 CFR Part 60, §60.7(c)(4)).

19.4.1.2 The summary report form shall contain the information and be in the format shown in Figure 1 of 40 CFR Part 60, §60.7 unless otherwise specified by the Division. One summary report form shall be submitted for each pollutant monitored at the facility

(40 CFR Part 60, §60.7(d)).

a. If the total duration of excess emissions for the reporting period is less than 1 percent (%) of the total operating time for the reporting period, and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) (Condition 19.4.1.1) need not be submitted unless requested by the Division (40 CFR Part 60, §60.7(d)(1)).

b. If the total duration of excess emissions for the reporting period is 1 percent (%) or greater of the total operating time for the reporting period, or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) (Condition 19.4.1.1) shall both be submitted (40 CFR Part 60, §60.7(d)(2)).

19.5 **Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Units 1 and 2 only**

19.5.1 The SO_2 CEMS shall be placed in a location to accurately monitor 100% of the flue gas, including any periods of bypass.

19.5.2 The Source must continuously and accurately monitor and report to the Division, pursuant to Section IX of the SIP component, the hourly average pressure drop across the mist eliminator and the hourly average flow rate for each unit at Units 1 and 2. The Source's pressure monitoring system shall be of sufficient sensitivity and reliability to enable consistent, continuous, and effective monitoring of the pressure drop range. The Source must take all necessary corrective actions to maintain the pressure drop within the applicable range.

19.5.3 The Source must provide to the Division on a quarterly basis all excess emission reports (EERs) for Craig Units 1 and 2 that describe in the form required by Section IX of the July 5, 2001 Colorado State Implementation Plan component, all excess readings, all claimed exemptions, and all other information required by law.

19.5.4 The Source must maintain, calibrate, and operate a method of coal sampling and analysis to determine accurately, pursuant to methods identified in Section 8(b)(viii) of the SIP component (see Condition 20), the potential emissions from sulfur in the coal entering the boiler reported in lb of SO_2 per MMBtu heat input.

19.5.5 The Source shall report to the Division on a quarterly basis each 30 day rolling average and each 90 day rolling average during the prior quarter that exceeded or failed to comply with the SO_2 emission limitations in Conditions 1.2.4 and 2.2.4. Each quarterly report shall include a list of the hours excluded for any reason from the determination of the Source's compliance with the SO_2 limits, and a list of times in which flue gas is bypassed around the FGD.

19.5.6 The Source must calculate hourly average NO_x concentrations in lb/MMBtu, in accordance with the requirements of 40 CFR Part 75. The Source must use the hourly averages to calculate calendar year averages in accordance with the requirements of 40 CFR Part 75.

19.5.7 The Source must report to the Division on a quarterly basis the Source's year-to-date average NO_x emission rate for that calendar year.

19.5.8 For any hour that valid, quality-assured CEMS data for a unit is unavailable, SO_2, NO_x, and CO_2 emissions shall be calculated in accordance with the missing data substitution procedures contained in 40 CFR Part 75 (Condition 19.3). For any day in which daily coal sample data are not available, the average potential SO_2 emission rate of coal from the previous 30 days as calculated in Conditions 1.2.4 and 2.2.4 shall be substituted.

19.5.9 The Source shall be bound by the data from their COMS, SO_2, CEMS and coal sampling data, and NO_x CEMS. The Source may not challenge the accuracy or credibility of their COMS, SO_2 CEMS and coal sampling data, and NO_x CEMS in any enforcement action unless otherwise expressly allowed by statue or regulation.

20. Coal Sampling

20.1 Coal must be sampled on at least a quarterly basis and must be analyzed to determine the heat content, weight percent sulfur, weight percent ash, and moisture content of the coal. The Source must follow Division approved coal sampling plan as shown in Appendix N (Colorado Regulation No. 3, Part C, Section V.C.5.).

20.2 In the event that more than one coal sampling analysis is performed during a quarter, the results of the analyses shall be averaged to determine quarterly average values for heat content, weight percent sulfur, and weight percent ash in the coal. These average values shall be used for subsequent calculations and demonstrations of compliance.

20.3 Coal sampling will follow the most current version of ASTM D2234, *Standard Practice for Collection of a Gross Sample of Coal*. Sample preparation will follow the most current version of ASTM 2013, *Standard Method of Preparing Coal Samples for Analysis*. Sulfur analysis will follow the most recent version of ASTM D4239, *Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods* (Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)).

20.4 In lieu of sampling under Condition 20.1, 20.2, and 20.3, vendor receipts, invoices, contracts, or other information may be used to provide the values for sulfur, ash, moisture, and heat content. Such alternative information shall indicate that coal sampling and analyses have been performed in accordance with the ASTM procedures, or equivalent, as identified in Condition 20.3.

20.5 Records of all coal analyses and vendor provided information must be maintained for Division inspection upon request.

21. Emission Factors

The Source shall comply with the provisions of Regulation No. 3 concerning APEN reporting. Except as provided for below, emission factors and/or other emission estimating methods that are specified within this permit cannot be adjusted without requiring a permit modification. Emission factors and/or other emission estimating methods used only to comply with the reporting requirements of Colorado Regulation No. 3, Part A, Section II can be updated and modified as specified in that Section. These changes by themselves do not require any permitting activities though the resulting emission estimate may trigger permitting activities.

22. Compliance Assurance Monitoring (CAM) Requirements

The CAM requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, apply to Units 1 (PM, SO_2), 2 (PM, SO_2, NO_x), and 3 (PM/PM_{10}, SO_2, NO_x), and to S102d, secondary coal crushing building (PM), as follows.

22.1 For Units 1 and 2 with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix G. Excursions, for purposes of reporting are as follows:

22.1.1 An opacity value greater than 15.0% occurring for 6 minutes or more.

22.2 For Units 1 and 2 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix J .Excursions, for purposes of reporting are as follows:

22.2.1 Any 30-day average of SO_2 emissions that exceed 0.11 lb/MMBtu.

22.3 For Unit 2 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix L. Excursions, for purposes of reporting are as follows:

22.3.1 Any 30-day average of NO_x emissions that exceed 0.08 lb/MMBtu.

22.4 For Unit 3 with respect to emissions of PM/PM_{10}, the Source shall follow the CAM plan provided in Appendix H. Excursions, for purposes of reporting are as follows:

22.4.1 An opacity value greater than 7.5% occurring for 6 minutes or more; or

22.4.2 Any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6.

22.5 For Unit 3 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix K. Exceedances, for the purposes of reporting are as follows:

22.5.1 Any 30-day average of SO_2 emissions that exceed 0.15 lb/MMBtu; or

22.5.2 Any daily average of SO_2 emissions that exceeds 0.20 lb/MMBtu.

22.6 For Unit 3 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix M. Exceedances, for the purposes of reporting are as follows:

22.6.1 Any 30-day average of NO_x emissions that exceed 0.28 lb/MMBtu.

22.7 For S102d with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix I. Excursions, for purposes of reporting are as follows:

22.7.1 Any visible emissions seen during Method 22 visible emissions observations; or

22.7.2 A pressure differential of less than 5 inches of water, or greater than 8 inches of water.

22.8 Excursions and/or exceedances shall be reported as required by Section V, Conditions 21 and 22.d of this permit (Colorado Regulation No. 3, Part C, Section V.C.5.).

22.9 Operation of Approved Monitoring

22.9.1 At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment (40 CFR Part 64, §64.7(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.2 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of these CAM requirements, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions (40 CFR Part 64, §64.7(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3 Response to excursions or exceedances

22.9.3.1 Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable (40 CFR Part 64, §64.7(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3.2 Determination of whether the owner of operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process (40 CFR Part 64, §64.7(d)(2), as adopted by

reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.4 After approval of the monitoring required under the CAM requirements, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Division and, if necessary submit a proposed modification for this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters (40 CFR Part 64, §64.7(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10 Quality Improvement Plan (QIP) Requirements

22.10.1 Based on the results of a determination made under the provisions of Condition 22.9.3.2, the Division may require the owner or operator to develop and implement a QIP (40 CFR Part 64, §64.8(a), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.2 The owner or operator shall maintain a written QIP, if required, and have it available for inspection (40 CFR Part 64, §64.8(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3 The QIP initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

22.10.3.1 Improved preventative maintenance practices (40 CFR Part 64, §64.8(b)(2)(i), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.2 Process operation changes (40 CFR Part 64, §64.8(b)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.3 Appropriate improvements to control methods (40 CFR Part 64, §64.8(b)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.4 Other steps appropriate to correct control performance (40 CFR Part 64, §64.8(b)(2)(iv), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.5 More frequent or improved monitoring (only in conjunction with one or more steps under Conditions 22.10.3.1 through 22.10.3.4) (40 CFR Part 64, §64.8(b)(2)(v), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.4 If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP

was determined (40 CFR Part 64, §64.8(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.5 Following implementation of a QIP, upon any subsequent determination pursuant to Condition 22.9.3.2, the Division or the U.S. EPA may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

22.10.5.1 Failed to address the cause of the control device performance problems (40 CFR Part 64, §64.8(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); or

22.10.5.2 Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions (40 CFR Part 64, §64.8(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.6 Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act (40 CFR Part 64, §64.8(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11 Reporting and Recordkeeping Requirements

22.11.1 Reporting Requirements: The reports required by Section V, Condition 22.d, shall contain the information specified in Appendix B of the permit and the following information, as applicable:

22.11.1.1 Summary information on the number, duration and cause (including unknown cause, if applicable), for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable) (40 CFR Part 64, §64.9(a)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); and

22.11.1.2 The owner or operator shall submit, if necessary, a description of the actions taken to implement a QIP during the reporting period as specified in Condition 22.10 of this permit. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring (40 CFR Part 64 § 64.9(a)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2 General Recordkeeping Requirements: In addition to the recordkeeping requirements in Section V, Condition 22.a through c.

22.11.2.1 The owner or operator shall maintain records of any written QIP required pursuant to Condition 22.10 and any activities undertaken to implement a QIP, and any supporting information required to be maintained under these CAM requirements

(such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions) (40 CFR Part 64 § 64.9(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2.2 Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements (40 CFR Part 64, §64.9(b)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12 Savings Provisions

22.12.1 Nothing in these CAM requirements shall excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act. These CAM requirements shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purposes of determining the monitoring to be imposed under separate authority under the federal clean air act, including monitoring in permits issued pursuant to title I of the federal clean air act. The purpose of the CAM requirements is to require, as part of the issuance of this Title V operating permit, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the requirements of CAM (40 CFR Part 64, §64.10(a)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.2 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to impose additional or more stringent monitoring, recordkeeping, testing or reporting requirements on any owner or operator of a source under any provision of the federal clean air act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.3 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to take any enforcement action under the federal clean air act for any violation of an applicable requirement or of any person to take action under section 304 of the federal clean air act (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

SECTION III - Acid Rain Requirements

1. Designated Representative and Alternate Designated Representative

Designated Representative
Name: Barbara Walz
Title: Senior Vice President – Policy & Compliance Chief Compliance Officer
Phone: (303) 452-6111

Alternate Designated Representative
Name: Barry Ingold
Title: Senior Vice President – Generation
Phone: (303) 452-6111

Note: Changes to the Designated and Alternative Designated Representatives shall be made according to the requirements of 40 CFR Part 72, §72.23.

2. Sulfur Dioxide Emission Allowances and Nitrogen Oxide Emission Limitations

	2016	2017	2018	2019	2020	2021
SO_2 Allowances, per 40 CFR Part 73.10(b), Table 2	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149	C1: 7678 C2: 7352 C3: 2149
NO_X Limits	C1, C2, C3: 0.46 lb/MMBtu of heat input on annual average basis (40 CFR Part 76, §76.7(a)(2))					

Under the provisions of 40 CFR Part 72, §72.84(a) any allowance allocations to, transfers to and deductions from an affected unit's Allowance Tracking System account is considered an automatic permit amendment and as such no revision to the permit is necessary. Numerical allowances shown in this table are from the 2013 edition of the CFR.

3. Standard Requirements (40 CFR Part 72, §72.9)

Boilers C1, C2, and C3 (Units 1, 2, and 3) are subject to the provisions of the Acid Rain Program as described herein. The Source has certified that they will comply with the following standard conditions.

3.1 Permit Requirements

3.1.1 The designated representative of each affected source and each affected unit at the source shall:

3.1.1.1 Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR Part 72 in accordance with the deadlines specified in 40 CFR Part 72, §72.30; and

3.1.1.2 Submit in a timely manner a complete reduced utilization plan if required under 40 CFR Part 72, §72.43; and

3.1.1.3 Submit in a timely manner any supplemental information that the permitting authority

determines is necessary to review an Acid Rain permit application and issue or deny an Acid Rain permit.

3.1.2 The owners and operators of each affected source and each affected unit at the source shall:

3.1.2.1 Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the Division; and

3.1.2.2 Have an Acid Rain Permit.

3.2 Monitoring Requirements

3.2.1 The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75.

3.2.2 The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

3.2.3 The requirements of 40 CFR Parts 74 and 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Federal Clean Air Act and other provisions of the operating permit for the source.

3.3 Sulfur Dioxide Requirements

3.3.1 The owners and operators of each source and each affected unit at the source shall:

3.3.1.1 Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR Part 73, §73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and

3.3.1.2 Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

3.3.2 Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Federal Clean Air Act.

3.3.3 An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

3.3.3.1 Starting January 1, 2000, an affected unit under 40 CFR Part 72, §72.6(a)(2); or

3.3.3.2 Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR Part 75, an affected unit under 40 CFR Part 72, §72.6(a)(3).

3.3.4 Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

3.3.5 An allowance shall not be deducted in order to comply with the requirements under Condition 3.3.1 of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

3.3.6 An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR Part 72, §72.7 and §72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

3.3.7 An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

3.4 Excess Emissions Requirements

3.4.1 The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan to the Administrator of the U. S. EPA, as required under 40 CFR Part 77.

3.4.2 The owners and operators of an affected unit that has excess emissions in any calendar year shall:

3.4.2.1 Pay without demand, to the Administrator of the U.S. EPA, the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and

3.4.2.2 Comply with the terms of an approved offset plan, as required by 40 CFR Part 77.

3.5 Recordkeeping and Reporting Requirements

3.5.1 Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or the Division:

3.5.1.1 The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR Part 72, §72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

3.5.1.2 All emissions monitoring information, in accordance with 40 CFR part 75; provided that to the extent that Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

3.5.1.3 Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

3.5.1.4 Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

3.5.2 The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72, Subpart I and 40 CFR Part 75.

3.6 Liability

3.6.1 Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR Part 70, §72.7 or §72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Federal Clean Air Act.

3.6.2 Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to Section 113(c) of the Federal Clean Air Act and 18 U.S.C. 1001.

3.6.3 No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

3.6.4 Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

3.6.5 Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

3.6.6 Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.

3.6.7 Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Federal Clean Air Act.

3.7 Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or a written exemption under 40 CFR Part 72, §72.7 or §72.8 shall be construed as:

3.7.1 Except as expressly provided in Title IV of the Federal Clean Air Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Federal Clean

Air Act, including the provisions of Title I of the Federal Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

3.7.2 Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Federal Clean Air Act;

3.7.3 Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

3.7.4 Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or

3.7.5 Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

4. Reporting Requirements

4.1 Reports shall be submitted to the addresses identified in Appendix D.

4.2 Pursuant to 40 CFR Part, §75.64 quarterly reports and compliance certification requirements shall be submitted to the Administrator **within 30 days after the end of the calendar quarter**. The contents of these reports shall meet the requirements of 40 CFR Part 75, §75.64.

4.3 Pursuant to 40 CFR Part 75, §75.65 excess emissions of opacity shall be reported to the Division. These reports shall be submitted in a format approved by the Division.

4.4 Revisions to this permit shall be made in accordance with 40 CFR Part 72, Subpart H, §72.80 through §72.85 (as adopted by reference in Colorado Regulation 18). Permit modification requests shall be submitted to the Division at the address identified in Appendix D.

5. Comments, Notes and Justifications

5.1 As set forth in 40 CFR Part 70, §72.22, the alternate designated representative may act on behalf of the designated representative for this Acid Rain Permit.

SECTION IV - Permit Shield

Regulation No. 3, 5 CCR 1001-5, Part C, §§ I.A.4, V.D. & XIII.B; § 25-7-114.4(3)(a), C.R.S.

1. Specific Non-Applicable Requirements

Based on the information available to the Division and supplied by the applicant, the following parameters and requirements have been specifically identified as non-applicable to the facility to which this permit has been issued. This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance. In addition, this shield does not protect the source from any violations that occur as a result of any modifications or reconstruction on which construction commenced prior to permit issuance.

Emission Unit Description & Number	Non-Applicable Requirement	Justification
B001 & B002 - Units 1 & 2	Construction Permit 10MF579 reference to May 1, 1973 Subpart D	The Units are subject to the most current version of Subpart D.
Facility-Wide	Colorado Regulation No. 1, V	Applies to coke ovens at Iron and steel plant operations only.
	Colorado Regulation No. 1, VII	Applies only to listed electric generating stations owned and operated by the Public Service Company of Colorado
	Colorado Regulation No. 1, VIII	Applies to listed stationary sources in the Denver PM_{10} nonattainment area only.
	Colorado Regulation No. 1, IX	Applies only to Refinery Fluid Bed Catalytic Cracking Units located in nonattainment areas for carbon monoxide
	Colorado Regulation No. 4, and General Condition 31 of this permit	Sale and use of wood burning devices does not apply to the Craig Station
	Colorado Regulation No. 7, except for Part B, Section III	Applies to sources in ozone nonattainment area. Part B, Section V applies in attainment areas, but diesel storage is exempt. Section V applies in attainment areas, but applies to crude oil storage tanks having a capacity of greater than 40,000 gallons. Part D, Section II, III, IV, and V apply in attainment areas, but contain provisions applicable to the oil and gas industry only.
	Colorado Regulation No. 8, Part D	Applies only to existing sources wishing to obtain a compliance extension and the Craig facility has not triggered this provision
	Colorado Regulation No. 9 – Open Burning, Prescribed Fire, and Permitting	Subject matter does not cover the Craig facility.
	Colorado Regulation No. 10 - Conformity Determinations Respecting Federal Actions	Subject matter does not cover the Craig facility.
	Colorado Regulation No. 11 - Motor Vehicle Emissions Inspection Program	Subject matter does not cover the Craig facility.

	Colorado Regulation No. 12 - Reduction of Diesel Vehicle Emissions	Geographic area of applicability does not include the Craig facility.
	Colorado Regulation No. 13 - The Oxygenated Fuels Program	Area of geographic applicability does not include the Craig facility.
	Colorado Regulation No. 16 - Street Sanding	Geographic area of applicability does not include the Craig facility.
	5CCR 1001-20 - Nonattainment Areas	Craig facility is not located in geographic areas classified as nonattainment.
	Colorado Regulation No. 19 - Lead Based Paint Abatement	Applies only to homes constructed prior to 1978, child-occupied facilities, and only those projects where the intent is to abate lead-based paint hazards
	40 CFR Part 55 - Outer Continental Shelf Air Regulations	Craig facility is outside the geographic scope of this provision.
	40 CFR Part 56 - Regional Consistency	Relates to authorities within the various offices of the EPA.

2. General Conditions

Compliance with this Operating Permit shall be deemed compliance with all applicable requirements specifically identified in the permit and other requirements specifically identified in the permit as not applicable to the source. This permit shield shall not alter or affect the following:

2.1 The provisions of §§ 25-7-112 and 25-7-113, C.R.S., or § 303 of the federal act, concerning enforcement in cases of emergency;

2.2 The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

2.3 The applicable requirements of the federal Acid Rain Program, consistent with § 408(a) of the federal act;

2.4 The ability of the Air Pollution Control Division to obtain information from a source pursuant to §25-7-111(2)(I), C.R.S., or the ability of the Administrator to obtain information pursuant to § 114 of the federal act;

2.5 The ability of the Air Pollution Control Division to reopen the Operating Permit for cause pursuant to Regulation No. 3, Part C, § XIII.

2.6 Sources are not shielded from terms and conditions that become applicable to the source subsequent to permit issuance.

3. Stream-lined Conditions

The following applicable requirements have been subsumed within this operating permit using the pertinent streamlining procedures approved by the U.S. EPA. For purposes of the permit shield,

compliance with the listed permit conditions will also serve as a compliance demonstration for purposes of the associated subsumed requirements.

Emission Unit Description & Number	Applicable Requirement	Justification
Section II, Conditions 1.2.5.2, 1.3.5.1, 2.2.5.2 and 2.3.4.2 (Units 1 & 2)	Colorado SIP, April 19, 2001 – Definition of "boiler operating day"	The Source requested that the definition of "boiler operating day" be "whenever coal is combusted" instead of what was defined in the CO SIP which was less stringent.
Section II, Conditions 3.2.2 & 3.3.3	NSPS Da definition of "boiler operating day"	The Source requested that the definition of "boiler operating day" use the most stringent definition of "whenever fossil fuel is combusted" in lieu of the NSPS definition.
Section II, Condition 1.9.3 & 2.9.3 (Units 1 & 2)	Colorado SIP, April 19, 2001 – Required quarterly reports	The included reporting requirement is more stringent since reports may be requested at any time by the Division with seven (7) days notice.
Section II, Condition 3.6 (Unit 3)	40 CFR Part 60, Subpart Da, §60.42Da(b) – Opacity not to exceed 20%, except for one 6-minute period per hour of not more than 27%	This requirement is less strict than the BACT limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.42Da(c)(1) – PM emissions not to exceed 0.015 lb/MMBtu	This requirement is less strict than the BACT PM limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.48Da(g) and (p) §60.49Da(t) and (v) – Options for PM CEMS to demonstrate compliance with NSPS Da PM requirements	Since the PM limit has been streamlined, so have these options which would have otherwise been included in the permit to demonstrate compliance with said limit.
Section II, Condition 3.1 (Unit 3)	40 CFR Part 60, Subpart Da, §60.48Da(o)(1) and (2) – PM monitoring with annual stack test and 24-hour opacity option for compliance demonstration with NSPS Da limits	Since the PM and opacity limits have been streamlined, so have these options which would have otherwise been included in the permit to demonstrate compliance with said limits.
Section II, Condition 3.6 (Unit 3)	40 CFR Part 60, Subpart Da, §60.52Da – Recordkeeping requirements for opacity observations	The opacity condition has been streamlined out under BACT wherein records are already required
Section II, Conditions 1.1, 2.1, 3.1 (Units 1, 2, & 3)	Colorado Regulation No. 1, Section II.A.1.c – PM emissions shall not exceed 0.1 lb/MMBtu	This limit is less strict than the Regional Haze (Units 1 & 2) and BACT (Unit 3) limits.
Section II, Condition 4 (Units 1, 2, & 3)	NSPS D/Da requirements associated with combusting non-coal fuels (40 CFR Part 60, Sections §60.43(a)(1), §60.43(b), §60.43(c), §60.44(a)(1), §60.44(a)(2), §60.44(b), §60.43Da(b), §60.43Da(b)(1)/(2), §60.44Da(a)(1), §60.44Da(a)(2)	So long as the fuel heat input limit under Condition 4 is met, these NSPS limits will change less than 2% as compared to the only-coal combustion requirements.

Section II, Condition 13.1	Colorado Construction Permit 98MF0141 – Annual Circulating Water Throughput: 94,608 * 10^6 gallons/year	This limit is merely the annualized PTE of the short term limit.
Section II, Condition 17.2 (Units 1 & 2)	Colorado Regulation No. 23, Section V.B.1. – Regional Haze stack testing	Testing under 40 CFR Part 63, Subpart UUUUU (MATS) is more stringent.
Section II, Condition 19 (Units 1, 2, & 3)	Colorado Regulation No. 1, Section IV – COMS and CEMS	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the CO Reg 1 requirements.
Section II, Condition 19 (Units 1, 2, & 3)	40 CFR Part 60, Subpart D, §60.45 – COMS and CEMS	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the CO Reg 1 requirements.
Section II, Condition 19 (Units 1 & 2)	Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Section VI.13 – CEMS for Units 1 and 2 (NO_x, SO_2, CO_2, and flow)	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the SIP requirements.
Section II, Condition 19 (Units 1 & 2)	Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) Section VI.10 – COMS for Units 1 and 2	The CEMS and COMS section contains requirements under 40 CFR Parts 60 and 75 which encompass the SIP requirements.

SECTION V - General Permit Conditions (ver 1/21/2020)

1. Administrative Changes

Regulation No. 3, 5 CCR 1001-5, Part A, § III.

The permittee shall submit an application for an administrative permit amendment to the Division for those permit changes that are described in Regulation No. 3, Part A, § I.B.1. The permittee may immediately make the change upon submission of the application to the Division.

2. Certification Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.9., V.C.16.a.& e. and V.C.17.

a. Any application, report, document and compliance certification submitted to the Air Pollution Control Division pursuant to Regulation No. 3 or the Operating Permit shall contain a certification by a responsible official of the truth, accuracy and completeness of such form, report or certification stating that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

b. All compliance certifications for terms and conditions in the Operating Permit shall be submitted to the Air Pollution Control Division at least annually unless a more frequent period is specified in the applicable requirement or by the Division in the Operating Permit.

c. Compliance certifications shall contain:

(i) the identification of each permit term and condition that is the basis of the certification;

(ii) the compliance status of the source;

(iii) whether compliance was continuous or intermittent;

(iv) method(s) used for determining the compliance status of the source, currently and over the reporting period; and

(v) such other facts as the Air Pollution Control Division may require to determine the compliance status of the source.

d. All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

e. If the permittee is required to develop and register a risk management plan pursuant to § 112(r) of the federal act, the permittee shall certify its compliance with that requirement; the Operating Permit shall not incorporate the contents of the risk management plan as a permit term or condition.

3. Common Provisions

Common Provisions Regulation, 5 CCR 1001-2 §§ II.A., II.B., II.C., II.E., II.F., II.I, and II.J

a. To Control Emissions Leaving Colorado

When emissions generated from sources in Colorado cross the State boundary line, such emissions shall not cause the air quality standards of the receiving State to be exceeded, provided reciprocal action is taken by the receiving State.

b. Emission Monitoring Requirements

The Division may require owners or operators of stationary air pollution sources to install, maintain, and use instrumentation to monitor and record emission data as a basis for periodic reports to the Division.

c. Performance Testing

The owner or operator of any air pollution source shall, upon request of the Division, conduct performance test(s) and furnish the Division a written report of the results of such test(s) in order to determine compliance with applicable emission control regulations.

Performance test(s) shall be conducted and the data reduced in accordance with the applicable reference test methods unless the Division:

(i) specifies or approves, in specific cases, the use of a test method with minor changes in methodology;

(ii) approves the use of an equivalent method;

(iii) approves the use of an alternative method the results of which the Division has determined to be adequate for indicating where a specific source is in compliance; or

(iv) waives the requirement for performance test(s) because the owner or operator of a source has demonstrated by other means to the Division's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Commission's or Division's authority to require testing under the Colorado Revised Statutes, Title 25, Article 7, and pursuant to regulations promulgated by the Commission.

Compliance test(s) shall be conducted under such conditions as the Division shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Division such records as may be necessary to determine the conditions of the performance test(s). Operations during period of startup, shutdown, and malfunction shall not constitute representative conditions of performance test(s) unless otherwise specified in the applicable standard.

The owner or operator of an affected facility shall provide the Division thirty days prior notice of the performance test to afford the Division the opportunity to have an observer present. The Division may waive the thirty day notice requirement provided that arrangements satisfactory to the Division are made for earlier testing.

The owner or operator of an affected facility shall provide, or cause to be provided, performance testing facilities as follows:

(i) Sampling ports adequate for test methods applicable to such facility;

(ii) Safe sampling platform(s);

(iii) Safe access to sampling platform(s); and

(iv) Utilities for sampling and testing equipment.

Each performance test shall consist of at least three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic mean of results of at least three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the owner or operator's control, compliance may, upon the Division's approval, be determined using the arithmetic mean of the results of the two other runs.

Nothing in this section shall abrogate the Division's authority to conduct its own performance test(s) if so warranted.

d. Affirmative Defense Provision for Excess Emissions during Malfunctions

An affirmative defense to a claim of violation under these regulations is provided to owners and operators for civil penalty actions for excess emissions during periods of malfunction. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of evidence that:

(i) The excess emissions were caused by a sudden, unavoidable breakdown of equipment, or a sudden, unavoidable failure of a process to operate in the normal or usual manner, beyond the reasonable control of the owner or operator;

(ii) The excess emissions did not stem from any activity or event that could have reasonably been foreseen and avoided, or planned for, and could not have been avoided by better operation and maintenance practices;

(iii) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded;

(iv) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(v) All reasonably possible steps were taken to minimize the impact of the excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence;

(viii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(ix) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This section is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement; and

(x) During the period of excess emissions, there were no exceedances of the relevant ambient air quality standards established in the Commissions' Regulations that could be attributed to the emitting source.

The owner or operator of the facility experiencing excess emissions during a malfunction shall notify the division verbally as soon as possible, but no later than noon of the Division's next working day, and shall submit written notification following the initial occurrence of the excess emissions by the end of the source's next reporting period. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to failures to meet federally promulgated performance standards or emission limits, including, but not limited to, new source performance standards and national emission standards for hazardous air pollutants. The affirmative defense provision does not apply to state implementation plan (sip) limits or permit limits that have been set taking into account potential emissions during malfunctions, including, but not necessarily limited to, certain limits with 30-day or longer averaging times, limits that indicate they apply during malfunctions, and limits that indicate they apply at all times or without exception.

e. Circumvention Clause

A person shall not build, erect, install, or use any article, machine, equipment, condition, or any contrivance, the use of which, without resulting in a reduction in the total release of air pollutants to the atmosphere, reduces or conceals

an emission which would otherwise constitute a violation of this regulation. No person shall circumvent this regulation by using more openings than is considered normal practice by the industry or activity in question.

f. Compliance Certifications

For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in the Colorado State Implementation Plan, nothing in the Colorado State Implementation Plan shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. Evidence that has the effect of making any relevant standard or permit term more stringent shall not be credible for proving a violation of the standard or permit term.

When compliance or non-compliance is demonstrated by a test or procedure provided by permit or other applicable requirement, the owner or operator shall be presumed to be in compliance or non-compliance unless other relevant credible evidence overcomes that presumption.

g. Affirmative Defense Provision for Excess Emissions During Startup and Shutdown

An affirmative defense is provided to owners and operators for civil penalty actions for excess emissions during periods of startup and shutdown. To establish the affirmative defense and to be relieved of a civil penalty in any action to enforce an applicable requirement, the owner or operator of the facility must meet the notification requirements below in a timely manner and prove by a preponderance of the evidence that:

(i) The periods of excess emissions that occurred during startup and shutdown were short and infrequent and could not have been prevented through careful planning and design;

(ii) The excess emissions were not part of a recurring pattern indicative of inadequate design, operation or maintenance;

(iii) If the excess emissions were caused by a bypass (an intentional diversion of control equipment), then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(iv) The frequency and duration of operation in startup and shutdown periods were minimized to the maximum extent practicable;

(v) All possible steps were taken to minimize the impact of excess emissions on ambient air quality;

(vi) All emissions monitoring systems were kept in operation (if at all possible);

(vii) The owner or operator's actions during the period of excess emissions were documented by properly signed, contemporaneous operating logs or other relevant evidence; and,

(viii) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions. This subparagraph is intended solely to be a factor in determining whether an affirmative defense is available to an owner or operator, and shall not constitute an additional applicable requirement.

The owner or operator of the facility experiencing excess emissions during startup and shutdown shall notify the Division verbally as soon as possible, but no later than two (2) hours after the start of the next working day, and shall submit written quarterly notification following the initial occurrence of the excess emissions. The notification shall address the criteria set forth above.

The Affirmative Defense Provision contained in this section shall not be available to claims for injunctive relief.

The Affirmative Defense Provision does not apply to State Implementation Plan provisions or other requirements that derive from new source performance standards or national emissions standards for hazardous air pollutants, or any other federally enforceable performance standard or emission limit with an averaging time greater than twenty-four

hours. In addition, an affirmative defense cannot be used by a single source or small group of sources where the excess emissions have the potential to cause an exceedance of the ambient air quality standards or Prevention of Significant Deterioration (PSD) increments.

In making any determination whether a source established an affirmative defense, the Division shall consider the information within the notification required above and any other information the Division deems necessary, which may include, but is not limited to, physical inspection of the facility and review of documentation pertaining to the maintenance and operation of process and air pollution control equipment.

4. Compliance Requirements

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.C.9., V.C.11. & 16.d. and § 25-7-122.1(2), C.R.S.

a. The permittee must comply with all conditions of the Operating Permit. Any permit noncompliance relating to federally-enforceable terms or conditions constitutes a violation of the federal act, as well as the state act and Regulation No. 3. Any permit noncompliance relating to state-only terms or conditions constitutes a violation of the state act and Regulation No. 3, shall be enforceable pursuant to state law, and shall not be enforceable by citizens under § 304 of the federal act. Any such violation of the federal act, the state act or regulations implementing either statute is grounds for enforcement action, for permit termination, revocation and reissuance or modification or for denial of a permit renewal application.

b. It shall not be a defense for a permittee in an enforcement action or a consideration in favor of a permittee in a permit termination, revocation or modification action or action denying a permit renewal application that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit.

c. The permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of any request by the permittee for a permit modification, revocation and reissuance, or termination, or any notification of planned changes or anticipated noncompliance does not stay any permit condition, except as provided in §§ X. and XI. of Regulation No. 3, Part C.

d. The permittee shall furnish to the Air Pollution Control Division, within a reasonable time as specified by the Division, any information that the Division may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee shall also furnish to the Division copies of records required to be kept by the permittee, including information claimed to be confidential. Any information subject to a claim of confidentiality shall be specifically identified and submitted separately from information not subject to the claim.

e. Any schedule for compliance for applicable requirements with which the source is not in compliance at the time of permit issuance shall be supplemental, and shall not sanction noncompliance with, the applicable requirements on which it is based.

f. For any compliance schedule for applicable requirements with which the source is not in compliance at the time of permit issuance, the permittee shall submit, at least every 6 months unless a more frequent period is specified in the applicable requirement or by the Air Pollution Control Division, progress reports which contain the following:

   (i) dates for achieving the activities, milestones, or compliance required in the schedule for compliance, and dates when such activities, milestones, or compliance were achieved; and

   (ii) an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted.

g. The permittee shall not knowingly falsify, tamper with, or render inaccurate any monitoring device or method required to be maintained or followed under the terms and conditions of the Operating Permit.

5. Emergency Provisions

Regulation No. 3, 5 CCR 1001-5, Part C, § VII

An emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed the technology-based emission limitation under the permit due to unavoidable increases in emissions attributable to the emergency. "Emergency" does not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error. An emergency constitutes an affirmative defense to an enforcement action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates, through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. an emergency occurred and that the permittee can identify the cause(s) of the emergency;

b. the permitted facility was at the time being properly operated;

c. during the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the permit; and

d. the permittee submitted oral notice of the emergency to the Air Pollution Control Division no later than noon of the next working day following the emergency, and followed by written notice within one month of the time when emissions limitations were exceeded due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

This emergency provision is in addition to any emergency or malfunction provision contained in any applicable requirement.

6. Emission Controls for Asbestos

Regulation No. 8, 5 CCR 1001-10, Part B

The permittee shall not conduct any asbestos abatement activities except in accordance with the provisions of Regulation No. 8, Part B, “asbestos control.”

7. Emissions Trading, Marketable Permits, Economic Incentives

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.13.

No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are specifically provided for in the permit.

8. Fee Payment

C.R.S §§ 25-7-114.1(6) and 25-7-114.7

a. The permittee shall pay an annual emissions fee in accordance with the provisions of C.R.S. § 25-7-114.7. A 1% per month late payment fee shall be assessed against any invoice amounts not paid in full on the 91st day after the date of invoice, unless a permittee has filed a timely protest to the invoice amount.

b. The permittee shall pay a permit processing fee in accordance with the provisions of C.R.S. § 25-7-114.7. If the Division estimates that processing of the permit will take more than 30 hours, it will notify the permittee of its estimate of what the actual charges may be prior to commencing any work exceeding the 30 hour limit.

c. The permittee shall pay an APEN fee in accordance with the provisions of C.R.S. § 25-7-114.1(6) for each APEN or revised APEN filed.

9. Fugitive Particulate Emissions

Regulation No. 1, 5 CCR 1001-3, § III.D.1.

The permittee shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions into the atmosphere, in accordance with the provisions of Regulation No. 1, § III.D.1.

10. Inspection and Entry

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.16.b.

Upon presentation of credentials and other documents as may be required by law, the permittee shall allow the Air Pollution Control Division, or any authorized representative, to perform the following:

a. enter upon the permittee's premises where an Operating Permit source is located, or emissions-related activity is conducted, or where records must be kept under the terms of the permit;

b. have access to, and copy, at reasonable times, any records that must be kept under the conditions of the permit;

c. inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the Operating Permit;

d. sample or monitor at reasonable times, for the purposes of assuring compliance with the Operating Permit or applicable requirements, any substances or parameters.

11. Minor Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, §§ X. & XI.

The permittee shall submit an application for a minor permit modification before making the change requested in the application. The permit shield shall not extend to minor permit modifications.

12. New Source Review

Regulation No. 3, 5 CCR 1001-5, Parts B & D

The permittee shall not commence construction or modification of a source required to be reviewed under the New Source Review provisions of Regulation No. 3, Parts B and/or D, as applicable, without first receiving a construction permit.

13. No Property Rights Conveyed

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.11.d.

This permit does not convey any property rights of any sort, or any exclusive privilege.

14. Odor

Regulation No. 2, 5 CCR 1001-4, Part A

As a matter of state law only, the permittee shall comply with the provisions of Regulation No. 2 concerning odorous emissions.

15. Off-Permit Changes to the Source

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.B.

The permittee shall record any off-permit change to the source that causes the emissions of a regulated pollutant subject to an applicable requirement, but not otherwise regulated under the permit, and the emissions resulting from the change, including any other data necessary to show compliance with applicable ambient air quality standards. The permittee shall provide contemporaneous notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permit shield shall not apply to any off-permit change.

16. Opacity

Regulation No. 1, 5 CCR 1001-3, §§ I., II.

The permittee shall comply with the opacity emissions limitation set forth in Regulation No. 1, §§ I.- II.

17. Open Burning

Regulation No. 9, 5 CCR 1001-11

The permittee shall obtain a permit from the Division for any regulated open burning activities in accordance with provisions of Regulation No. 9.

18. Ozone Depleting Compounds

Regulation No. 15, 5 CCR 1001-19

The permittee shall comply with the provisions of Regulation No. 15 concerning emissions of ozone depleting compounds. Sections I., II.C., II.D., III. IV., and V. of Regulation No. 15 shall be enforced as a matter of state law only.

19. Permit Expiration and Renewal

Regulation No. 3, 5 CCR 1001-5, Part C, §§ III.B.6., IV.C., V.C.2.

a. The permit term shall be five (5) years. The permit shall expire at the end of its term. Permit expiration terminates the permittee's right to operate unless a timely and complete renewal application is submitted.

b. Applications for renewal shall be submitted at least twelve months, but not more than 18 months, prior to the expiration of the Operating Permit. An application for permit renewal may address only those portions of the permit that require revision, supplementing, or deletion, incorporating the remaining permit terms by reference from the previous permit. A copy of any materials incorporated by reference must be included with the application.

20. Portable Sources

Regulation No. 3, 5 CCR 1001-5, Part C, § II.D.

Portable Source permittees shall notify the Air Pollution Control Division at least 10 days in advance of each change in location.

21. Prompt Deviation Reporting

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.7.b.

The permittee shall promptly report any deviation from permit requirements, including those attributable to malfunction conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken.

"Prompt" is defined as follows:

a. Any definition of "prompt" or a specific timeframe for reporting deviations provided in an underlying applicable requirement as identified in this permit; or

b. Where the underlying applicable requirement fails to address the time frame for reporting deviations, reports of deviations will be submitted based on the following schedule:

   (i) For emissions of a hazardous air pollutant or a toxic air pollutant (as identified in the applicable regulation) that continue for more than an hour in excess of permit requirements, the report shall be made within 24 hours of the occurrence;

(ii) For emissions of any regulated air pollutant, excluding a hazardous air pollutant or a toxic air pollutant that continue for more than two hours in excess of permit requirements, the report shall be made within 48 hours; and

(iii) For all other deviations from permit requirements, the report shall be submitted every six (6) months, except as otherwise specified by the Division in the permit in accordance with paragraph 22.d. below.

c. If any of the conditions in paragraphs b.i or b.ii above are met, the source shall notify the Division by telephone (303-692-3155) or facsimile (303-782-0278) based on the timetables listed above. *[Explanatory note: Notification by telephone or facsimile must specify that this notification is a deviation report for an Operating Permit.]* A written notice, certified consistent with General Condition 2.a. above (Certification Requirements), shall be submitted within 10 working days of the occurrence. All deviations reported under this section shall also be identified in the 6-month report required above.

"Prompt reporting" does not constitute an exception to the requirements of "Emergency Provisions" for the purpose of avoiding enforcement actions.

22. Record Keeping and Reporting Requirements

Regulation No. 3, 5 CCR 1001-5, Part A, § II.; Part C, §§ V.C.6., V.C.7.

a. Unless otherwise provided in the source specific conditions of this Operating Permit, the permittee shall maintain compliance monitoring records that include the following information:

(i) date, place as defined in the Operating Permit, and time of sampling or measurements;

(ii) date(s) on which analyses were performed;

(iii) the company or entity that performed the analysis;

(iv) the analytical techniques or methods used;

(v) the results of such analysis; and

(vi) the operating conditions at the time of sampling or measurement.

b. The permittee shall retain records of all required monitoring data and support information for a period of at least five (5) years from the date of the monitoring sample, measurement, report or application. Support information, for this purpose, includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the Operating Permit. With prior approval of the Air Pollution Control Division, the permittee may maintain any of the above records in a computerized form.

c. Permittees must retain records of all required monitoring data and support information for the most recent twelve (12) month period, as well as compliance certifications for the past five (5) years on-site at all times. A permittee shall make available for the Air Pollution Control Division's review all other records of required monitoring data and support information required to be retained by the permittee upon 48 hours advance notice by the Division.

d. The permittee shall submit to the Air Pollution Control Division all reports of any required monitoring at least every six (6) months, unless an applicable requirement, the compliance assurance monitoring rule, or the Division requires submission on a more frequent basis. All instances of deviations from any permit requirements must be clearly identified in such reports.

e. The permittee shall file an Air Pollutant Emissions Notice ("APEN") prior to constructing, modifying, or altering any facility, process, activity which constitutes a stationary source from which air pollutants are or are to be emitted, unless such source is exempt from the APEN filing requirements of Regulation No. 3, Part A, § II.D or as provided for in Regulation No. 3, Part A, § II.A.2 for oil and gas well production facilities. A revised APEN shall be filed

annually whenever a significant change in emissions, as defined in Regulation No. 3, Part A, § II.C.2., occurs; whenever there is a change in owner or operator of any facility, process, or activity; whenever new control equipment is installed; whenever a different type of control equipment replaces an existing type of control equipment; whenever a permit limitation must be modified; or before the APEN expires. An APEN is valid for a period of five years. The five-year period recommences when a revised APEN is received by the Air Pollution Control Division. Revised APENs shall be submitted no later than 30 days before the five-year term expires. Permittees submitting revised APENs to inform the Division of a change in actual emission rates must do so by April 30 of the following year. Where a permit revision is required, the revised APEN must be filed along with a request for permit revision. APENs for changes in control equipment must be submitted before the change occurs, except an APEN shall be filed once per year for control equipment at condensate storage tanks located at oil and gas exploration and production facilities subject to Regulation No. 7, Part D § I. Annual fees are based on the most recent APEN on file with the Division.

23. Reopenings for Cause

Regulation No. 3, 5 CCR 1001-5, Part C, § XIII.

a. The Air Pollution Control Division shall reopen, revise, and reissue Operating Permits; permit reopenings and reissuance shall be processed using the procedures set forth in Regulation No. 3, Part C, § III., except that proceedings to reopen and reissue permits affect only those parts of the permit for which cause to reopen exists.

b. The Division shall reopen a permit whenever additional applicable requirements become applicable to a major source with a remaining permit term of three or more years, unless the effective date of the requirements is later than the date on which the permit expires, or unless a general permit is obtained to address the new requirements; whenever additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program; whenever the Division determines the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit; or whenever the Division determines that the permit must be revised or revoked to assure compliance with an applicable requirement.

c. The Division shall provide 30 days' advance notice to the permittee of its intent to reopen the permit, except that a shorter notice may be provided in the case of an emergency.

d. The permit shield shall extend to those parts of the permit that have been changed pursuant to the reopening and reissuance procedure.

24. Requirements for Major Stationary Sources

Regulation No. 3, 5 CCR 1001-5, Part D, §§ V.A.7.c & d, VI.B.5 & VI.B.6

The following provisions apply to projects at existing emissions units at a major stationary source (other than projects at a source with a PAL) that are not part of a major modification and where the owner or operator relies on projected actual emissions. The definitions of baseline actual emissions, major modification, major stationary source, PAL, projected actual emissions, regulated NSR pollutant and significant can be found in Regulation No. 3, Part D, § II.A.

a. Before beginning actual construction of the project, the owner or operator shall document and maintain a record of the following information:

(i) a description of the project;

(ii) identification of the emissions unit(s) whose emissions of a regulated NSR pollutant could be affected by the project; and

(iii) a description of the applicability test used to determine the project is not a major modification for any regulated NSR pollutants, including the baseline actual emissions, the projected actual emissions, the amount of emissions excluded and an explanation for why such amount was excluded, and any netting calculations, if applicable.

b. The owner or operator shall monitor emissions of any regulated NSR pollutant that could increase as a result of the project from any emissions units identified in paragraph a.(ii) and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operation after the change, or for a period of ten (10) years following resumption of regular operation after the change if the project increases the design capacity or potential to emit of that regulated NSR pollutant at such emissions unit.

c. For existing electric utility steam generating units the following requirements apply:

(i) Before beginning actual construction, the owner or operator shall provide a copy of the information required by paragraph a above to the Division. The owner or operator is not required to obtain a determination from the Division prior to beginning actual construction.

(ii) The owner or operate shall submit a report to the Division within sixty days after the end of each year during which records must be generated under paragraph b above setting out the unit's annual emissions during the calendar year that preceded submission of the report.

d. For existing emissions units that are not electric utility steam generating units, the owner or operator shall submit a report to the Division if the annual emissions from the project, in tons per year, exceed the baseline actual emissions (documented and maintained per paragraph a(iii)) by a significant amount for that regulated NSR pollutant, and if such emissions differ from the preconstruction projection (documented and maintained per paragraph a.(iii)). Such report shall be submitted to the Division within sixty days after the end of such year. The report shall contain the following:

(i) The name, address and telephone number of the owner or operator;

(ii) The annual emissions as calculated per paragraph b; and

(iii) Any other information that the owner or operator wishes to include in the report.

e. The owner of operation of the source shall make the information in paragraph a available for review upon request to the Division or the general public.

25. Section 502(b)(10) Changes

Regulation No. 3, 5 CCR 1001-5, Part C, § XII.A.

The permittee shall provide a minimum 7-day advance notification to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit. The permittee shall attach a copy of each such notice given to its Operating Permit.

26. Severability Clause

Regulation No. 3, 5 CCR 1001-5, Part C, § V.C.10.

In the event of a challenge to any portion of the permit, all emissions limits, specific and general conditions, monitoring, record keeping and reporting requirements of the permit, except those being challenged, remain valid and enforceable.

27. Significant Permit Modifications

Regulation No. 3, 5 CCR 1001-5, Part C, § III.B.2.

The permittee shall not make a significant modification required to be reviewed under Regulation No. 3, Part B ("Construction Permit" requirements) without first receiving a construction permit. The permittee shall submit a complete Operating Permit application or application for an Operating Permit revision for any new or modified source within twelve months of commencing operation, to the address listed in Item 1 in Appendix D of this permit. If the permittee chooses to use the "Combined Construction/Operating Permit" application procedures of Regulation No. 3, Part C, then the Operating Permit must be received prior to commencing construction of the new or modified source.

28. Special Provisions Concerning the Acid Rain Program

Regulation No. 3, 5 CCR 1001-5, Part C, §§ V.C.1.b. & 8

a. Where an applicable requirement of the federal act is more stringent than an applicable requirement of regulations promulgated under Title IV of the federal act, 40 Code of Federal Regulations (CFR) Part 72, both provisions shall be incorporated into the permit and shall be federally enforceable.

b. Emissions exceeding any allowances that the source lawfully holds under Title IV of the federal act or the regulations promulgated thereunder, 40 CFR Part 72, are expressly prohibited.

29. Transfer or Assignment of Ownership

Regulation No. 3, 5 CCR 1001-5, Part C, § II.C.

No transfer or assignment of ownership of the Operating Permit source will be effective unless the prospective owner or operator applies to the Air Pollution Control Division on Division-supplied Administrative Permit Amendment forms, for reissuance of the existing Operating Permit. No administrative permit shall be complete until a written agreement containing a specific date for transfer of permit, responsibility, coverage, and liability between the permittee and the prospective owner or operator has been submitted to the Division.

30. Volatile Organic Compounds

Regulation No. 7, 5 CCR 1001-9, Part B, §§ I & III.

The requirements in paragraphs a, b and e apply to sources located in the Denver 1-hour ozone attainment/maintenance area, any nonattainment area for the 1-hour ozone standard and to the 8-hour Ozone Control Area and on a state-only basis to sources located in any ozone nonattainment area, which includes areas designated nonattainment for either the 1-hour or 8-hour ozone standard, unless otherwise specified in Regulation No. 7, Part A, Section I.A.1.c. The requirements in paragraphs c and d apply statewide.

a. All storage tank gauging devices, anti-rotation devices, accesses, seals, hatches, roof drainage systems, support structures, and pressure relief valves shall be maintained and operated to prevent detectable vapor loss except when opened, actuated, or used for necessary and proper activities (e.g. maintenance). Such opening, actuation, or use shall be limited so as to minimize vapor loss.

   Detectable vapor loss shall be determined visually, by touch, by presence of odor, or using a portable hydrocarbon analyzer. When an analyzer is used, detectable vapor loss means a VOC concentration exceeding 10,000 ppm. Testing shall be conducted as in Regulation No. 7, Part B, Section VI.C.3.

b. Except as otherwise provided by Regulation No. 7, all volatile organic compounds, excluding petroleum liquids, transferred to any tank, container, or vehicle compartment with a capacity exceeding 212 liters (56 gallons), shall be transferred using submerged or bottom filling equipment. For top loading, the fill tube shall reach within six inches of the bottom of the tank compartment. For bottom-fill operations, the inlet shall be flush with the tank bottom.

c. No person shall dispose of volatile organic compounds by evaporation or spillage unless Reasonably Available Control Technology (RACT) is utilized.

d. No owner or operator of a bulk gasoline terminal, bulk gasoline plant, or gasoline dispensing facility as defined in Colorado Regulation No. 7, Part B, Sections IV.C.2., IV.C.3. and VII.A.3., shall permit gasoline to be intentionally

spilled, discarded in sewers, stored in open containers, or disposed of in any other manner that would result in evaporation.

e. Beer production and associated beer container storage and transfer operations involving volatile organic compounds with a true vapor pressure of less than 1.5 psia actual conditions are exempt from the provisions of paragraph b, above.

31. Wood Stoves and Wood burning Appliances

Regulation No. 4, 5 CCR 1001-6

The permittee shall comply with the provisions of Regulation No. 4 concerning the advertisement, sale, installation, and use of wood stoves and wood burning appliances.

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DISCLAIMER: None of the information found in these Appendices shall be considered to be State or Federally enforceable, except as otherwise provided in the permit, and is presented to assist the source, permitting authority, inspectors, and citizens.

A. Appendix A - Inspection Information

A.I. Directions to Plant:

The facility is located approximately 5 miles south of Craig, CO near Highway 13. Ranney Street, which goes south from the town of Craig, also leads to Craig Station

A.II. Safety Equipment Required:

Eye Protection; Hard Hat; Safety Shoes; Hearing Protection

A.III. Facility Plot Plan:

The attached Figures (following the insignificant activities list) shows the plot plan as submitted via email on March 20, 2018.

A.IV. List of Insignificant Activities:

The following list of insignificant activities was provided by the source to assist in the understanding of the facility layout. Since there is no requirement to update such a list, activities may have changed since the last filing.

For insignificant activities marked with an asterisk (*) the owner or operator must maintain sufficient recordkeeping to verify that the exemption applies (e.g., annual throughput is less than 400,000 gallons). Such records shall be made available for Division review upon request (Colorado Regulation No. 3, Part C, Section II.E).

A.IV.1. Noncommercial (in-house) experimental and analytical laboratory equipment which is bench scale in nature including quality control/quality assurance laboratories, process support laboratories, environmental laboratories supporting a manufacturing or industrial facility, and research and development laboratories (Colorado Regulation No. 3, Part C, Section II.E.3.i.(i))

A.IV.2. *Disturbance of surface areas for purposes of land development, which do not exceed 25 contiguous acres and which do not exceed six months in duration. (This does not include mining operations or disturbance of contaminated soil.) (Section II.E.3.j.)

A.IV.3. *Each individual piece of fuel burning equipment, other than smokehouse generators and internal combustion engines, which uses gaseous fuel, and which has a design rate less than or equal to 5 million Btu per hour. (See definition of fuel burning equipment, Common Provisions Regulation) (Section II.E.3.k.)

A.IV.4. *Chemical storage tanks or containers that hold less than 500 gallons, and which have a daily throughput less than 25 gallons per day (Section II.E.3.n.)

A.IV.5. *Landscaping and site housekeeping devices equal to or less than 10 HP in size (lawnmowers, trimmers, snow blowers, etc.) (Section II.E.3.bb.)

A.IV.6. *Chemical storage areas where chemicals are stored in closed containers, and where total storage capacity does not exceed 5000 gallons. This exemption applies solely to storage of such chemicals. This exemption does not apply to transfer of chemicals from, to, or between such containers. (Section II.E.3.mm.)

A.IV.7. Storage of butane, propane, or liquefied petroleum gas in a vessel with a capacity of less than 60,000 gallons, provided the requirements of Regulation No. 7, Section IV are met, where applicable. (Section II.E.3.zz.)

A.IV.8. Storage tanks of capacity less than 40,000 gallons of lubricating oils. (Section II.E.3.aaa.)

A.IV.9. Fuel storage and dispensing equipment in ozone attainment areas operated solely for company-owned vehicles where the daily fuel throughput is no more than 400 gallons per day, averaged annually. (Section II.E.3.ccc.)

A.IV.10. *Storage tanks meeting all of the following criteria (Section II.E.3.fff.):

A.IV.10.i. Annual throughput is less than 400,000 gallons; and

A.IV.10.ii. The liquid is one of the following:

(a) Diesel fuels 1-D, 2-D or 4-D;

(b) Fuel oils #1 through #6;

(c) Gas turbine fuels 1-GT through 4-GT;

(d) An oil/water mixture with a vapor pressure lower than that of diesel fuel (Reid vapor pressure of 0.025 PSIA).

A.IV.11. Each individual piece of fuel burning equipment which uses gaseous fuel, and which has a design rate less than or equal to 10 million Btu per hour, and which is solely for heating buildings for personal comfort. (Section III.E.3.ggg.)

A.IV.12. Stationary Internal Combustion Engines which (Section II.E.3.nnn.):

A.IV.12.i. Power portable drilling rigs; or

A.IV.12.ii. Are emergency power generators which have a rated horsepower of less than 260; or operate no more than 250 hours per year and have a rated horsepower of less than 737; or operate no more than 100 hours per year and have a rated horsepower of less than 1840; or

A.IV.12.iii. Have actual emissions less than five tons per year or rated horsepower of less than 50.

A.IV.13. *Air pollution emission units, operations or activities with emissions less than the appropriate de minimis reporting level. (Section II.E.3.a.)

A.IV.14. *Emergency diesel fire-pump engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 1,068 hours per year.)

A.IV.15. *Unit 1 & 2 emergency diesel generator engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 389 hours per year.)

A.IV.16. *Unit 3 emergency diesel generator engine (Note that this engine will no longer qualify for the less than five tons per year actual emissions exemption (Section II.E.3.nnn.(iii)) if it operates for more than 764 hours per year.)

A.IV.17. 3,200 Btu/hr propane space heater @ west warehouse (Section III.E.3.ggg.)

A.IV.18. 500 gallon propane tank @ east warehouse (Section II.E.3.zz.)

A.IV.19. No. 2 Fuel Oil Tank - 500,000 gallons (Section II.E.3.fff.)

A.IV.20. No. 2 Fuel Oil Tank - 500,000 gallons (Section II.E.3.fff.)

A.IV.21. *Plant Solvent Parts Cleaners (Section II.E.3.a.)

A.IV.22. *Emergency Generator Fuel Oil Day Tank Vent (100 gal) (Section II.E.3.a.)

A.IV.23. *Aboveground Diesel Tank Vent - Diesel (12,000 gal) (Section II.E.3.a.)

A.IV.24. *Aboveground Gasoline Tank Vent (10,000 gal) (Section II.E.3.a.)

A.IV.25. Chemical Laboratory (Section II.E.3.i.(i))

A.IV.26. 8,500 gallon #2 Diesel Tank (Section II.E.3.fff.)

A.IV.27. 8,500 gallon #2 Diesel Tank (Section II.E.3.fff.)

A.IV.28. *Hauling Miscellaneous Wet Wastes (Section II.E.3.a.)

A.IV.29. *Bottom Ash Storage and Handling (Section II.E.3.a.)

A.IV.30. *Dry Outage Waste Handling/Hauling (Section II.E.3.a.)

A.IV.31. *Gritblasting and sandblasting activities during outages (Section II.E.3.a.)

A.IV.32. Street and Parking Lot Striping (Section II.E.3.s.)

A.IV.33. Aerosol Can Usage (Section II.E.3.u.)

A.IV.34. Road and Lot Paving (Section II.E.3.x.)

A.IV.35. *Limestone Handling/Hauling for Road Repair and Pond Rip-Rap (Section II.E.3.a.)

A.IV.36. *Limestone Storage Piles (Section II.E.3.a.)

A.IV.37. Welding Operations (Section II.E.3.r.)

A.IV.38. *Used Oil Space Heater (Section III.E.3.a.)

A.IV.39. *Various Oil or Propane-Fired Heaters ranging from 500,000 to 900,000 Btu/hr (Section III.E.3.a.)

A.IV.40. *Unit 1 and 2 Limestone Transfer Conveyors (Section II.E.3.a.)

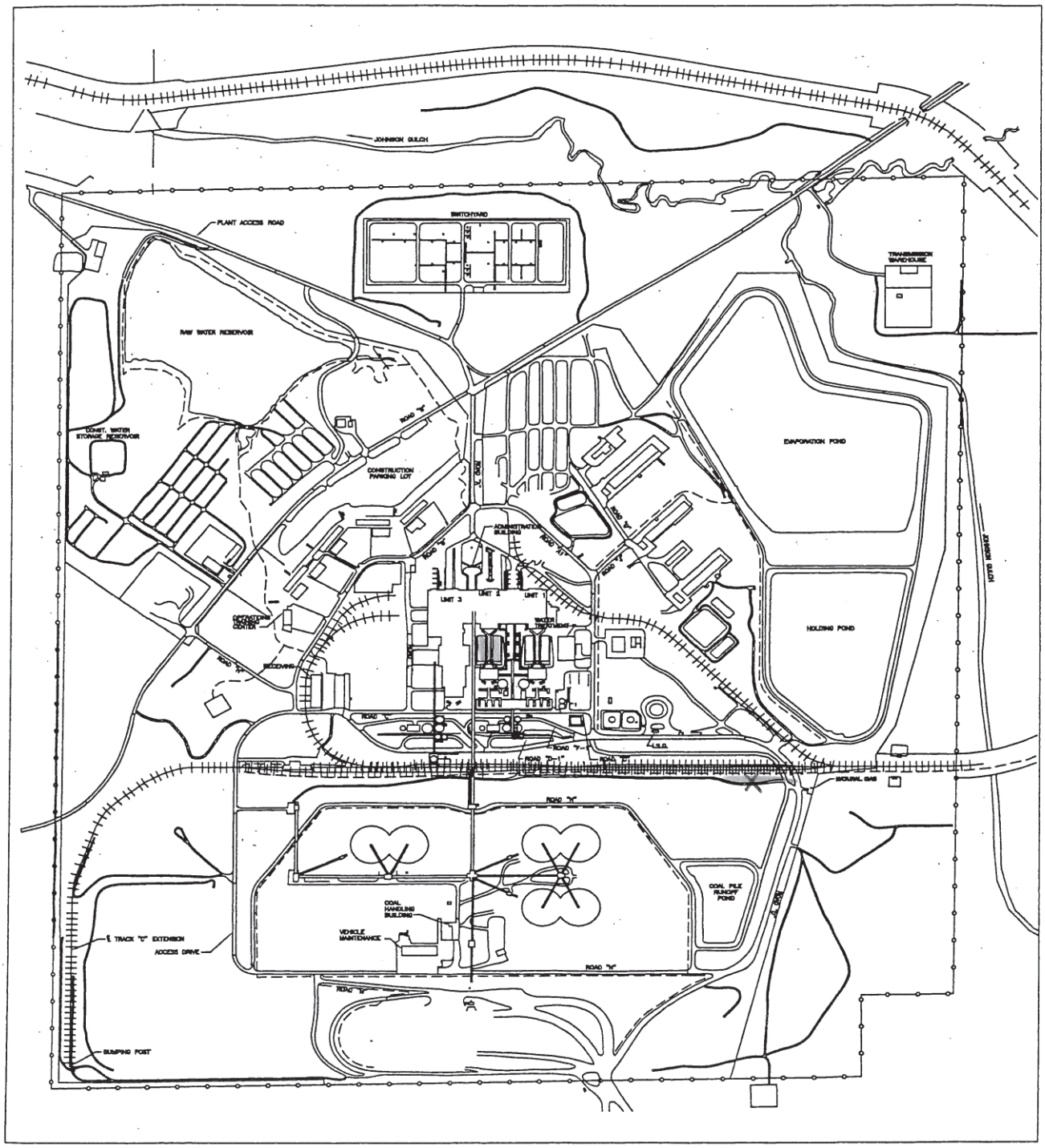
A.IV.41. *Dry Sorbent Injection Silo (Section II.E.3.a.)

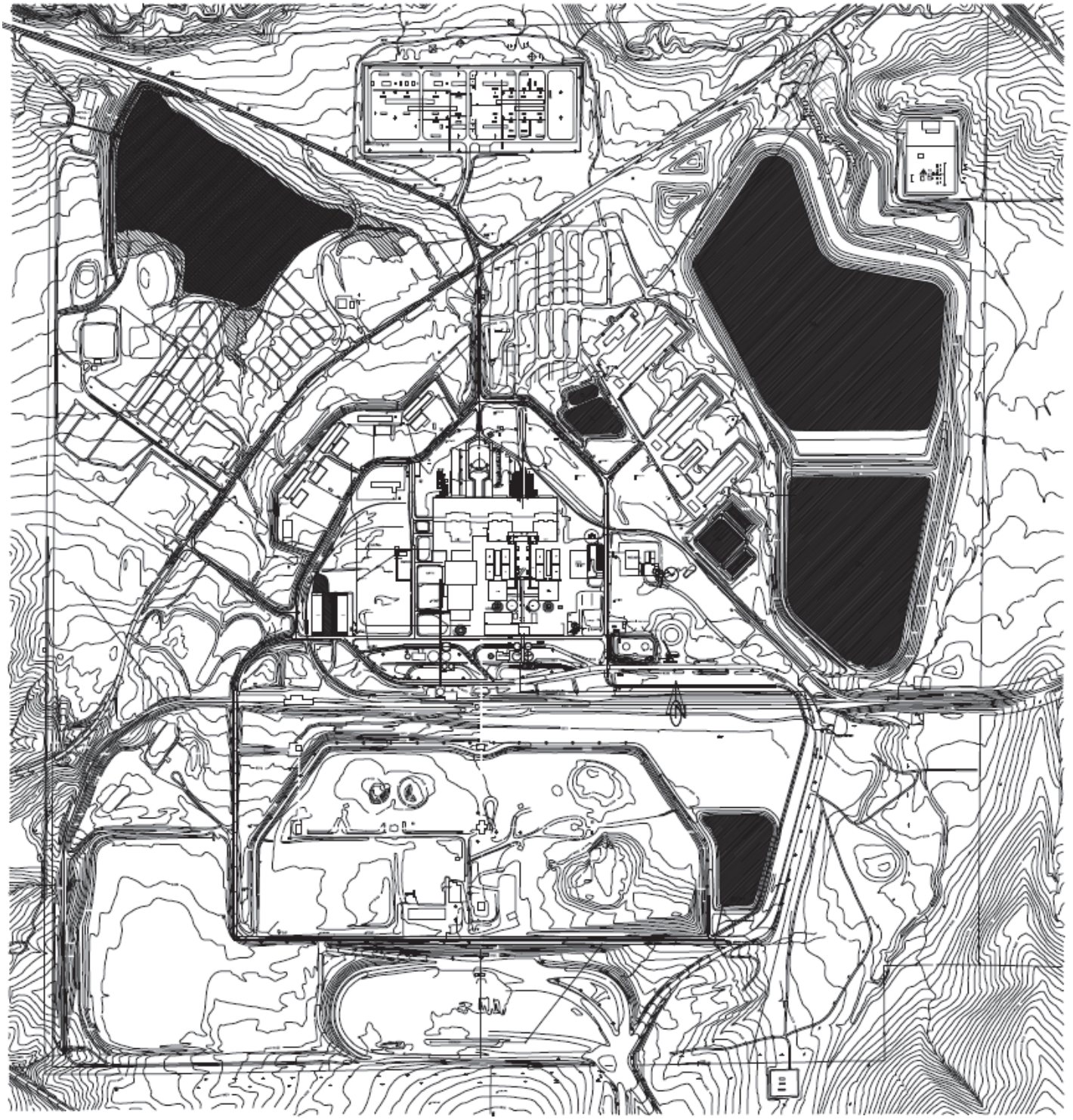
A.IV.42. *Anhydrous Ammonia Storage (Two 50,000 Gallon Tanks) and Transport System (Section II.E.3.a.)

A.IV.43. *Urea Storage and Transport System (Section II.E.3.a.)

A.IV.44. *Common Coal Drive House (Section II.E.3.a.)

A.IV.45. *Light Plants and Small Portable Generators and Welders (Section II.E.3.a.)


JOHNSON GULCH
PLANT ACCESS ROAD
SWITCHYARD
RAW WATER RESERVOIR
CONST. WATER STORAGE RESERVOIR
CONSTRUCTION PARKING LOT
ROAD "A"
ROAD "B"
ROAD "C"
ROAD "D"
ROAD "E"
ROAD "F"
ROAD "G"
ROAD "H"
ROAD "I"
ROAD "J"
ROAD "K"
ADMINISTRATION BUILDING
UNIT 3
UNIT 2
UNIT 1
WATER TREATMENT
OPERATIONS TRAINING CENTER
SECONDARY
EVAPORATION POND
HOLDING POND
TRANSMISSION WAREHOUSE
ACCESS ROAD
SEWAGE
COAL HANDLING BUILDING
VEHICLE MAINTENANCE
COAL PILE RUNOFF POND
TRACK "C" EXTENSION
ACCESS DRIVE
BUMPING POST



B. Appendix B – Reporting Requirements and Definitions

Version 8/20/2014, with codes

Please note that, pursuant to 113(c)(2) of the federal Clean Air Act, any person who knowingly:

(A) Makes any false material statement, representation, or certification in, or omits material information from, or knowingly alters, conceals, or fails to file or maintain any notice, application, record, report, plan, or other document required pursuant to the Act to be either filed or maintained (whether with respect to the requirements imposed by the Administrator or by a State);

(B) Fails to notify or report as required under the Act; or

(C) Falsifies, tampers with, renders inaccurate, or fails to install any monitoring device or method required to be maintained or followed under the Act shall, upon conviction, be punished by a fine pursuant to title 18 of the United States Code, or by imprisonment for not more than 2 years, or both. If a conviction of any person under this paragraph is for a violation committed after a first conviction of such person under this paragraph, the maximum punishment shall be doubled with respect to both the fine and imprisonment.

The Source must comply with all conditions of this operating permit. Any permit noncompliance constitutes a violation of the Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

The Part 70 Operating Permit program requires three types of reports to be filed for all permits. All required reports must be certified by a responsible official.

Report #1: Monitoring Deviation Report (due at least every six months)

For purposes of this operating permit, the Division is requiring that the monitoring reports are due every six months unless otherwise noted in the permit. All instances of deviations from permit monitoring requirements must be clearly identified in such reports.

For purposes of this operating permit, monitoring means any condition determined by observation, by data from any monitoring protocol, or by any other monitoring which is required by the permit as well as the recordkeeping associated with that monitoring. This would include, for example, fuel use or process rate monitoring, fuel analyses, and operational or control device parameter monitoring.

Report #2: Permit Deviation Report (must be reported "promptly")

In addition to the monitoring requirements set forth in the permits as discussed above, each and every requirement of the permit is subject to deviation reporting. The reports must address deviations from permit requirements, including those attributable to malfunctions as defined in this Appendix, the probable cause of such deviations, and any corrective actions or preventive measures taken. All deviations from any term or condition of the permit are required to be summarized or referenced in the annual compliance certification.

For purposes of this operating permit, "malfunction" shall refer to both emergency conditions and malfunctions. Additional discussion on these conditions is provided later in this Appendix.

For purposes of this operating permit, the Division is requiring that the permit deviation reports are due as set forth in General Condition 21. Where the underlying applicable requirement contains a definition of prompt or otherwise specifies a time frame for reporting deviations, that definition or time frame shall govern. For example, quarterly Excess Emission Reports required by an NSPS or Regulation No. 1, Section IV.

In addition to the monitoring deviations discussed above, included in the meaning of deviation for the purposes of this operating permit are any of the following:

(1) A situation where emissions exceed an emission limitation or standard contained in the permit;

(2) A situation where process or control device parameter values demonstrate that an emission limitation or standard contained in the permit has not been met;

(3) A situation in which observations or data collected demonstrates noncompliance with an emission limitation or standard or any work practice or operating condition required by the permit; or,

(4) A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred. (only if the emission point is subject to CAM)

For reporting purposes, the Division has combined the Monitoring Deviation Report with the Permit Deviation Report. All deviations shall be reported using the following codes:

1 = Standard:	When the requirement is an emission limit or standard
2 = Process:	When the requirement is a production/process limit
3 = Monitor:	When the requirement is monitoring
4 = Test:	When the requirement is testing
5 = Maintenance:	When required maintenance is not performed
6 = Record:	When the requirement is recordkeeping
7 = Report:	When the requirement is reporting
8 = CAM:	A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other:	When the deviation is not covered by any of the above categories

Report #3: Compliance Certification (annually, as defined in the permit)

Submission of compliance certifications with terms and conditions in the permit, including emission limitations, standards, or work practices, is required not less than annually.

Compliance Certifications are intended to state the compliance status of each requirement of the permit over the certification period. They must be based, at a minimum, on the testing and monitoring methods specified in the permit that were conducted during the relevant time period. In addition, if the

owner or operator knows of other material information (i.e. information beyond required monitoring that has been specifically assessed in relation to how the information potentially affects compliance status), that information must be identified and addressed in the compliance certification. The compliance certification must include the following:

- The identification of each term or condition of the permit that is the basis of the certification;
- Whether or not the method(s) used by the owner or operator for determining the compliance status with each permit term and condition during the certification period was the method(s) specified in the permit. Such methods and other means shall include, at a minimum, the methods and means required in the permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with section 113(c)(2) of the Federal Clean Air Act, which prohibits knowingly making a false certification or omitting material information;
- The status of compliance with the terms and conditions of the permit, and whether compliance was continuous or intermittent. The certification shall identify each deviation and take it into account in the compliance certification. Note that not all deviations are considered violations.[1]
- Such other facts as the Division may require, consistent with the applicable requirements to which the source is subject, to determine the compliance status of the source.

The Certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred (only for emission points subject to CAM).

Note the requirement that the certification shall identify each deviation and take it into account in the compliance certification. Previously submitted deviation reports, including the deviation report submitted at the time of the annual certification, may be referenced in the compliance certification.

[1] For example, given the various emissions limitations and monitoring requirements to which a source may be subject, a deviation from one requirement may not be a deviation under another requirement which recognizes an exception and/or special circumstances relating to that same event.

Startup, Shutdown, Malfunctions and Emergencies,

Understanding the application of Startup, Shutdown, Malfunctions and Emergency Provisions, is very important in both the deviation reports and the annual compliance certifications.

Startup, Shutdown, and Malfunctions

Please note that exceedances of some New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) standards that occur during Startup, Shutdown or Malfunctions may not be considered to be non-compliance since emission limits or standards often do not apply unless specifically stated in the NSPS. Such exceedances must, however, be reported as excess emissions per the NSPS/MACT rules and would still be noted in the deviation report. In regard to compliance certifications, the permittee should be confident of the information related to those deviations when making compliance determinations since they are subject to Division review. The concepts of Startup, Shutdown and Malfunctions also exist for Best Available Control Technology (BACT) sources, but are not applied in the same fashion as for NSPS and MACT sources.

Emergency Provisions

Under the Emergency provisions of Part 70 certain operational conditions may act as an affirmative defense against enforcement action if they are properly reported.

DEFINITIONS

Malfunction (NSPS) means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Malfunction (SIP) means any sudden and unavoidable failure of air pollution control equipment or process equipment or unintended failure of a process to operate in a normal or usual manner. Failures that are primarily caused by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

Emergency means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation, and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

B.I. Appendix B – Monitoring and Permit Deviation Report - Part I

B.I.1. Following is the **required** format for the Monitoring and Permit Deviation report to be submitted to the Division as set forth in General Condition 21. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

B.I.2. Part II of this Appendix B shows the format and information the Division will require for describing periods of monitoring and permit deviations, or malfunction or emergency conditions as indicated in the Table below. One Part II Form must be completed for each Deviation. Previously submitted reports (e.g. EER's or malfunctions) may be referenced and the form need not be filled out in its entirety.

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:_____ (see first page of the permit for specific reporting period and dates)

Emission Unit	Facility ID	Unit Description	Deviations noted During Period?[1]		Deviation Code [2]	Malfunction/Emergency Condition Reported During Period?	
			YES	NO		YES	NO
Unit 1	B001	Coal-Fired Boiler: Babcock & Wilcox #NB24157					
Unit 2	B002	Coal-Fired Boiler: Babcock & Wilcox #NB24156					
Unit 3	B003	Coal-Fired Boiler: Babcock & Wilcox #NB24602					
Coal Handling – Units 1 & 2	P101	F101a – Coal hauling – Units 1 & 2					
		F101b – Coal unloading to grizzly – Units 1 & 2					
		F101c – Coal surge pile					
		S101d – Primary coal crushing – Units 1 & 2					
		S101e – Secondary coal crushing building – Units 1 & 2					
		S101f – Common Coal Transfer Building Belt A					
		S101g – Common Coal Transfer Building Belt B					
		S101h – Coal stackout building – Units 1 & 2					
		F101i – Coal stackout – Units 1 & 2					
		F101j – Coal storage piles – Units 1 & 2					
		S101k – Coal reclaim A – Units 1 & 2					

		S101l – Coal reclaim B – Units 1 & 2					
		S101m – Coal tripper deck & silos – Units 1 & 2					
Ash Handling – Units 1 & 2	P203	S203a – Ash storage silo A – Units 1 & 2					
		S203b – Ash storage silo B – Units 1 & 2					
		F203c – Ash truck loading – Units 1 & 2					
		S203d – Silo B dry ash unloading – Units 1 & 2					
		S203e – Silo A dry ash unloading – Units 1 & 2					
Limestone Handling – Units 1 & 2	P201	F201a – Limestone hauling					
		S201b – Limestone truck unloading					
		S201c – Limestone silo #1 – Units 1 & 2					
		S201d – Limestone silo #2 – Units 1 & 2					
Coal Handling – Unit 3	P102	F102a – Coal train unloading – Unit 3					
		S102b – Coal conveyor portal building – Unit 3					
		S102c – Coal conveyor portal building – Unit 3					
		S102d – Secondary coal crushing (2 crushers) – Unit 3					
		S102e – Coal stackout building – Unit 3					
		F102f – Coal stackout – Unit 3					
		F102g – Coal storage pile – Unit 3					
		S102h – Coal reclaim system – Unit 3					
		S102i – Coal tripper deck & silos – Unit 3					
		S102j – Loadout coal to railcars – Unit 3					
		S102k – Common coal transfer building extension					
		F102l – Coal train loading					
Ash Handling – Unit 3	P204	S204a – Ash storage silo – Unit 3					
		F204b – Ash truck loading – Unit 3					
		S204c – Recycle ash truck					
		F204d – Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, and 3					
Lime Handling – Unit 3	P202	F202a – Lime hauling					
		S202b – Lime unloading					
		S202c – Lime conveying and silo					

		S202d – Lime day bin					
Cooling Towers – Units 1 & 2	P401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74					
	P402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74					
Cooling Tower – Unit 3	P403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79					
Emergency Fire-Pump Engine	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower					
Units 1&2 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower					
Unit 3 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower					
General Conditions							
Insignificant Activities							

[1] See previous discussion regarding what is considered to be a deviation. Determination of whether or not a deviation has occurred shall be based on a reasonable inquiry using readily available information.

[2] Use the following entries, as appropriate

1 = Standard: When the requirement is an emission limit or standard
2 = Process: When the requirement is a production/process limit
3 = Monitor: When the requirement is monitoring
4 = Test: When the requirement is testing
5 = Maintenance: When required maintenance is not performed
6 = Record: When the requirement is recordkeeping
7 = Report: When the requirement is reporting
8 = CAM: A situation in which an excursion or exceedance as defined in 40CFR Part 64 (the Compliance Assurance Monitoring (CAM) Rule) has occurred.
9 = Other: When the deviation is not covered by any of the above categories

B.II. Appendix B – Monitoring and Permit Deviation Report - Part II

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:

Is the deviation being claimed as an: Emergency _____ Malfunction_____ N/A

(For NSPS/MACT) Did the deviation occur during: Startup _____ Shutdown _____ Malfunction _____

Normal Operation _____

OPERATING PERMIT UNIT IDENTIFICATION:

Operating Permit Condition Number Citation

Explanation of Period of Deviation

Duration (start/stop date & time)

Action Taken to Correct the Problem

Measures Taken to Prevent a Reoccurrence of the Problem

Dates of Malfunctions/Emergencies Reported (if applicable)

Deviation Code _____ Division Code QA: _____

SEE EXAMPLE ON THE NEXT PAGE

EXAMPLE

FACILITY NAME: U.S.S. Enterprise
OPERATING PERMIT NO: 64OPZZXXX
REPORTING PERIOD: 1/1/2369 - 6/30/2369

Is the deviation being claimed as an: Emergency / **Malfunction** / N/A

(For NSPS/MACT) Did the deviation occur during: Startup / Shutdown / **Malfunction** / Normal Operation

OPERATING PERMIT UNIT IDENTIFICATION:

Holodeck generator with nanobot-repaired filtration system – Unit TNG

Operating Permit Condition Number Citation

Section II, Condition 3.1 - Opacity Limitation

Explanation of Period of Deviation

Tribbles in the console

Duration

START- 1730 4/10/2369
END- 1800 4/10/2369

Action Taken to Correct the Problem

Transported Tribbles to Klingon vessel.

Measures Taken to Prevent Reoccurrence of the Problem

Permanent ban of Tribbles as pets. Increased structural integrity of console.

Dates of Malfunction/Emergencies Reported (if applicable)

5/30/2369 to J.L. Picard, APCD

Deviation Code _____ Division Code QA: _____

B.III. Appendix B – Monitoring and Permit Deviation Report - Part III

REPORT CERTIFICATION

SOURCE NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station

FACILITY IDENTIFICATION NUMBER: 081-0018

PERMIT NUMBER: 96OPMF155

REPORTING PERIOD:_____ (see first page of the permit for specific reporting period and dates)

All information for the Title V Semi-Annual Deviation Reports must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

STATEMENT OF COMPLETENESS

I have reviewed the information being submitted in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this submittal are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in Sub-Section 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of Sub-Section 25-7 122.1, C.R.S.

Printed or Typed Name Title

Signature of Responsible Official Date Signed

Note: Deviation reports shall be submitted to the Division at the address given in Appendix D of this permit. No copies need be sent to the U.S. EPA.

C. Appendix C – Required Format for Annual Compliance Certification Reports

Following is the format for the Compliance Certification report to be submitted to the Division and the U.S. EPA annually based on the effective date of the permit. The Table below must be completed for all equipment or processes for which specific Operating Permit terms exist.

FACILITY NAME: Tri-State Generation and Transmission Association, Inc. – Craig Station
OPERATING PERMIT NO: 96OPMF155
REPORTING PERIOD:

I. Facility Status

___ During the entire reporting period, this source was in compliance with **ALL** terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference. The method(s) used to determine compliance is/are the method(s) specified in the Permit.

___ With the possible exception of the deviations identified in the table below, this source was in compliance with all terms and conditions contained in the Permit, each term and condition of which is identified and included by this reference, during the entire reporting period. The method used to determine compliance for each term and condition is the method specified in the Permit, unless otherwise indicated and described in the deviation report(s). Note that not all deviations are considered violations.

Emission Unit	Facility ID	Unit Description	Deviations Reported [1]		Monitoring Method per Permit?[2]		Was compliance continuous or intermittent?[3]	
			Previous	Current	YES	NO	YES	NO
Unit 1	B001	Coal-Fired Boiler: Babcock & Wilcox #NB24157						
Unit 2	B002	Coal-Fired Boiler: Babcock & Wilcox #NB24156						
Unit 3	B003	Coal-Fired Boiler: Babcock & Wilcox #NB24602						
Coal Handling – Units 1 & 2	P101	F101a – Coal hauling – Units 1 & 2						
		F101b – Coal unloading to grizzly – Units 1 & 2						
		F101c – Coal surge pile						
		S101d – Primary coal crushing – Units 1 & 2						
		S101e – Secondary coal crushing building – Units 1 & 2						
		S101f – Common Coal Transfer Building Belt A						
		S101g – Common Coal Transfer Building						

		Belt B						
		S101h – Coal stackout building – Units 1 & 2						
		F101i – Coal stackout – Units 1 & 2						
		F101j – Coal storage piles – Units 1 & 2						
		S101k – Coal reclaim A – Units 1 & 2						
		S101l – Coal reclaim B – Units 1 & 2						
		S101m – Coal tripper deck & silos – Units 1 & 2						
Ash Handling – Units 1 & 2	P203	S203a – Ash storage silo A – Units 1 & 2						
		S203b – Ash storage silo B – Units 1 & 2						
		F203c – Ash truck loading – Units 1 & 2						
		S203d – Silo B dry ash unloading – Units 1 & 2						
		S203e – Silo A dry ash unloading – Units 1 & 2						
Limestone Handling – Units 1 & 2	P201	F201a – Limestone hauling						
		S201b – Limestone truck unloading						
		S201c – Limestone silo #1 – Units 1 & 2						
		S201d – Limestone silo #2 – Units 1 & 2						
Coal Handling – Unit 3	P102	F102a – Coal train unloading – Unit 3						
		S102b – Coal conveyor portal building – Unit 3						
		S102c – Coal conveyor portal building – Unit 3						
		S102d – Secondary coal crushing (2 crushers) – Unit 3						
		S102e – Coal stackout building – Unit 3						
		F102f – Coal stackout – Unit 3						
		F102g – Coal storage pile – Unit 3						
		S102h – Coal reclaim system – Unit 3						
		S102i – Coal tripper deck & silos – Unit 3						
		S102j – Loadout coal to railcars – Unit 3						
		S102k – Common coal transfer building extension						
		F102l – Coal train loading						
Ash Handling – Unit 3	P204	S204a – Ash storage silo – Unit 3						
		F204b – Ash truck loading – Unit 3						

		S204c – Recycle ash truck						
		F204d – Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, and 3						
Lime Handling – Unit 3	P202	F202a – Lime hauling						
		S202b – Lime unloading						
		S202c – Lime conveying and silo						
		S202d – Lime day bin						
Cooling Towers – Units 1 & 2	P401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74						
	P402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74						
Cooling Tower – Unit 3	P403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79						
Emergency Fire-Pump Engine	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower						
Units 1&2 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower						
Unit 3 Emergency Diesel Generator	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower						
General Conditions								
Insignificant Activities[4]								

[1] If deviations were noted in a previous deviation report , put an "X" under "previous". If deviations were noted in the current deviation report (i.e. for the last six months of the annual reporting period), put an "X" under "current". Mark both columns if both apply.

[2] Note whether the method(s) used to determine the compliance status with each term and condition was the method(s) specified in the permit. If it was not, mark "no" and attach additional information/explanation.

[3] Note whether the compliance status with of each term and condition provided was continuous or intermittent. "Intermittent Compliance" can mean either that noncompliance has occurred or that the owner or operator has data sufficient to certify compliance only on an intermittent basis. Certification of intermittent compliance therefore does not necessarily mean that any noncompliance has occurred.

NOTE:

The Periodic Monitoring requirements of the Operating Permit program rule are intended to provide assurance that even in the absence of a continuous system of monitoring the Title V source can demonstrate whether it has operated in continuous compliance for the duration of the reporting period. Therefore, if a source 1) conducts all of the monitoring and recordkeeping required in its permit, even if such activities are done periodically and not continuously, and if 2) such monitoring and recordkeeping does not indicate non-

compliance, and if 3) the Responsible Official is not aware of any credible evidence that indicates non-compliance, then the Responsible Official can certify that the emission point(s) in question were in continuous compliance during the applicable time period.

[4] Compliance status for these sources shall be based on a reasonable inquiry using readily available information.

II. Status for Accidental Release Prevention Program:

A. This facility _____ is subject _____ is not subject to the provisions of the Accidental Release Prevention Program (Section 112(r) of the Federal Clean Air Act)

B. If subject: The facility _____ is _____ is not in compliance with all the requirements of section 112(r).

1. A Risk Management Plan _____ will be _____has been submitted to the appropriate authority and/or the designated central location by the required date.

III. Certification

All information for the Annual Compliance Certification must be certified by a responsible official as defined in Colorado Regulation No. 3, Part A, Section I.B. This signed certification document must be packaged with the documents being submitted.

I have reviewed this certification in its entirety and, based on information and belief formed after reasonable inquiry, I certify that the statements and information contained in this certification are true, accurate and complete.

Please note that the Colorado Statutes state that any person who knowingly, as defined in § 18-1-501(6), C.R.S., makes any false material statement, representation, or certification in this document is guilty of a misdemeanor and may be punished in accordance with the provisions of § 25-7 122.1, C.R.S.

Printed or Typed Name Title

Signature Date Signed

NOTE: All compliance certifications shall be submitted to the Air Pollution Control Division and to the Environmental Protection Agency at the addresses listed in Appendix D of this Permit.

D. Appendix D – Notification Addresses

D.I. Air Pollution Control Division

Colorado Department of Public Health and Environment
Air Pollution Control Division
Operating Permits Unit
APCD-SS-B1
4300 Cherry Creek Drive S.
Denver, CO 80246-1530
ATTN: Matt Burgett

D.II. United States Environmental Protection Agency

Compliance Notifications:

Office of Enforcement, Compliance and Environmental Justice
Mail Code 8ENF-AT
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

502(b)(10) Changes, Off Permit Changes:

Office of Partnerships and Regulatory Assistance
Mail Code 8P-AR
U.S. Environmental Protection Agency, Region VIII
1595 Wynkoop Street
Denver, CO 80202-1129

E. Appendix E – Permit Acronyms

Listed Alphabetically:

AIRS -	Aerometric Information Retrieval System
AP-42 -	EPA Document Compiling Air Pollutant Emission Factors
APEN -	Air Pollution Emission Notice (State of Colorado)
APCD -	Air Pollution Control Division (State of Colorado)
ASTM -	American Society for Testing and Materials
BACT -	Best Available Control Technology
BTU -	British Thermal Unit
CAA -	Clean Air Act (CAAA = Clean Air Act Amendments)
CCR -	Colorado Code of Regulations
CEM -	Continuous Emissions Monitor
CF -	Cubic Feet (SCF = Standard Cubic Feet)
CFR -	Code of Federal Regulations
CO -	Carbon Monoxide
COM -	Continuous Opacity Monitor
CRS -	Colorado Revised Statute
EF -	Emission Factor
EPA -	Environmental Protection Agency
FI -	Fuel Input Rate in MMBtu/hr
FR -	Federal Register
G -	Grams
Gal -	Gallon
GPM -	Gallons per Minute
HAPs -	Hazardous Air Pollutants
HP -	Horsepower
HP-HR -	Horsepower Hour (G/HP-HR = Grams per Horsepower Hour)
LAER -	Lowest Achievable Emission Rate
LBS -	Pounds
M -	Thousand
MM -	Million
MMscf -	Million Standard Cubic Feet
MMscfd -	Million Standard Cubic Feet per Day
N/A or NA -	Not Applicable
NOx -	Nitrogen Oxides
NESHAP -	National Emission Standards for Hazardous Air Pollutants
NSPS -	New Source Performance Standards
P -	Process Weight Rate in Tons/Hr
PE -	Particulate Emissions
PM -	Particulate Matter
PM_{10} -	Particulate Matter Under 10 Microns
PSD -	Prevention of Significant Deterioration
PTE -	Potential To Emit

RACT - Reasonably Available Control Technology
SCC - Source Classification Code
SCF - Standard Cubic Feet
SIC - Standard Industrial Classification
SO_2 - Sulfur Dioxide
TPY - Tons Per Year
TSP - Total Suspended Particulate
VOC - Volatile Organic Compounds

F. Appendix F – Permit Modifications

DATE OF REVISION	TYPE OF REVISION	SECTION NUMBER, CONDITION NUMBER	DESCRIPTION OF REVISION

G. Appendix G – Units 1 and 2 Baghouses Particulate Matter Compliance Assurance Monitoring Plan

G.I. Background

G.I.1. Emission Unit Description

G.I.1.i. Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

G.I.1.ii. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

G.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM requirements:

G.I.2.i. Unit 1:

(a) 0.10 lb/MMBtu heat input, 40 CFR Part 60, Subpart D, §60.42 (Condition 1.1.1);

(b) 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) (Condition 1.1.2); and

(c) 0.03 lb PM/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze (Condition 1.1.3).

G.I.2.ii. Unit 2:

(a) 0.10 lb/MMBtu heat input, 40 CFR Part 60, Subpart D, §60.42 (Condition 2.1.1);

(b) 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001) (Condition 2.1.2); and

(c) 0.03 lb/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze (Condition 2.1.3).

G.I.3. Monitoring Requirements

G.I.3.i. Visible emissions (opacity).

G.I.4. Control Technology

G.I.4.i. Each boiler is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouses have a particulate removal efficiency greater than 99%.

G.II. Monitoring Approach

	Indicator 1
I. Indicator	Visible Emissions (Opacity)
Measurement Approach	Opacity emissions will be monitored by a Continuous Opacity Monitor System (COMS).
II. Indicator Range	An excursion is defined as an opacity value greater than 15.0% for 6 minutes or more. When this occurs, the Source will perform an investigation to ascertain the cause of the excursion. In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60, Subpart A, §60.13. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60, Subpart A, § 60.13.

G.III. Justification

G.III.1. Background

G.III.1.i. The large pollutant specific emission units (PSEU) are two (2) coal fired boilers, that burn natural gas for startup, shutdown and/or flame stabilization. Each boiler is equipped with a baghouse to control particulate matter emissions.

G.III.1.ii. Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a

thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

G.IV. Rationale for Selection of Performance Indicators

G.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

G.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

G.IV.2.i. Visible Emissions (Opacity)

Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

G.V. Rationale for Selection of Indicator Ranges

G.V.1. Visible Emissions (Opacity)

G.V.1.i. In their May 1, 2009 Operating Permit renewal application, a CAM plan was submitted (with respect to PM emission limitations) for Units 1 and 2. In the application, the Source proposed visible emissions (short-term opacity) as an indicator. The Source proposed that an opacity reading greater than 15%, is an indication of potential reduction in baghouse performance. In response to this indicator, an investigation is triggered to locate the cause of the excursion. If the maintenance actions are taken, the results of the work performed are to be documented.

H. Appendix H – Unit 3 Baghouse Particulate Matter Compliance Assurance Monitoring Plan

H.I. Background

H.I.1. Emission Unit Description

H.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

H.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM/PM_{10} requirements:

H.I.2.i. Unit 3:

(a) 443 tons PM/year, 403 tons PM_{10}/year, Colorado Construction Permit 12MF322-1 (Condition 3.1.1.3) (Note that this limit includes both filterable and condensable PM/PM_{10}, but only the filterable portion of the emissions are subject to the CAM requirements as there is no control device for the condensable portion of the limit);

(b) 0.013 lb PM/MMBtu, 0.012 lb PM10/MMBtu, Colorado Construction Permit 12MF322-1 (Condition 3.1.1.1);

(c) 0.013 lb PM/MMBtu, 0.012 lb PM10/MMBtu, Colorado Regulation No. 23, Section IV.B – Regional Haze (Condition 3.1.2).

H.I.3. Monitoring Requirements:

H.I.3.i. Visible emissions (opacity).

H.I.4. Control Technology:

H.I.4.i. The boiler is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouse has a particulate removal efficiency greater than 99%.

H.II. Monitoring Approach

	Indicator 1
I. Indicator	Visible Emissions (Opacity)
Measurement Approach	Opacity emissions will be monitored by a Continuous Opacity Monitor System (COMS).

	Indicator 1
II. Indicator Range	An excursion is defined as an opacity value greater than 7.5% for 6 minutes or more. When this occurs, the Source will perform an investigation to ascertain the cause of the excursion. An excursion is also defined as any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6. In addition to the above, when an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria	
a. Data Representativeness	An increase in visible emissions (opacity) under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The COM equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Part 60 and the internal CEM Quality Control/Quality Assurance program developed in accordance with 40 CFR Part 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	Opacity measurements will be performed in accordance with the requirements in 40 CFR Part 60 Subpart A § 60.13. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	COM data shall be reduced to 6-minute averages as required by 40 CFR Part 60 Subpart A § 60.13. All 6-minute averages in each 24-hour period (midnight to midnight) will be averaged together to get a 24-hour average.

H.III. Justification

H.III.1. Background

H.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a baghouse to control particulate matter emissions.

H.III.1.ii. Particulate matter removal is accomplished by passing the flue gases through a porous fabric material. The solid particles buildup on the fabric surface to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

H.IV. Rationale for Selection of Performance Indicators

H.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the

monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

H.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

H.IV.2.i. Visible Emissions (Opacity)

(a) Based on the relationship between particulate matter in a flue gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

H.V. Rationale for Selection of Indicator Ranges

H.V.1. Visible Emissions (Opacity)

H.V.1.i. In the May 21, 2010 application to modify the Title V permit to incorporate the Unit 3 requirements, the Source submitted a CAM plan with respect to PM emission limitations. In the May 21, 2010 application, the Source proposed using a baseline opacity monitoring method, akin to the requirements in 40 CFR Part 60, Subpart Da, as an indicator. This method involves establishing a baseline opacity during PM performance testing and then comparing the 24-hour average opacity against the baseline. Any 24-hour average opacity value that exceeds the baseline level shall be cause for investigating the control device.

H.V.1.ii. The inclusion of the short-term opacity indicator of 7.5% over 6 minutes was chosen to reflect the necessity for continuous monitoring which was not completely covered by the Source's request for the baseline opacity monitoring method. A short-term opacity indicator is standard for this size of industrial boiler. The 7.5% value was chosen because it is below the BACT limit of 10% specified in Colorado Construction Permit 12MF322-1. If the baghouse is operating properly, opacity should be below 7.5%. The short-term opacity indicator serves to provide an indication of proper baghouse operation and can be a reasonable indicator that Unit 3 is in compliance with the PM limitations.

I. Appendix I – Coal Handling System for Unit 3 (P102), Secondary Coal Crushing Building (S102d) Particulate Matter Compliance Assurance Monitoring Plan

I.I. Background

I.I.1. Emission Unit Description

I.I.1.i. S102d – Secondary Coal Crushing Building for the P102 Coal Handling System for Unit 3. The building contains two crushers which process coal for Unit 3. The system can also process coal for Units 1 and 2, as necessary.

I.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable filterable PM requirements:

I.I.2.i. S102d:

(a) 1.7 tons PM/year, Colorado Construction Permit 12MF322-2 (Condition 7.2).

I.I.3. Monitoring Requirements:

I.I.3.i. Visible emissions; and

I.I.3.ii. Differential pressure monitoring.

I.I.4. Control Technology:

I.I.4.i. The secondary coal crushing building is equipped with a baghouse to control filterable particulate matter emissions generated from the combustion of coal. The baghouse has a particulate removal efficiency greater than 99%.

I.II. Monitoring Approach

	Indicator 1	Indicator 2
I. Indicator	Visible Emissions	Differential Pressure Monitoring
Measurement Approach	Visible emissions from the baghouse will be monitored monthly by conducting a six-minute visible emission observation in accordance with the procedures in Method 22 while the crushers are active.	The pressure drop across the baghouse will be monitored on a daily basis. Pre-baghouse and post-baghouse pressures will be reported to a system which will trigger an investigation should the differential pressure exceed the indicator threshold.

	Indicator 1	Indicator 2
II. Indicator Range	An excursion is defined as any visible emissions seen during the Method 22 test. When an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.	An excursion is defined as a pressure differential of less than 5 inches of water or greater than 8 inches of water. When an excursion occurs, the appropriate corrective action is made and repairs and/or replacements are made as necessary. A history of the corrective action(s) will be maintained at the facility and made available upon request.
III. Performance Criteria		
a. Data Representativeness	Visible emissions from the baghouse under steady-state operating conditions is an indirect indication of a potential increase in particulate matter emissions.	Measurements taken pre- and post-baghouse are used to calculate the differential pressure, indicating proper operation of the control device.
b. Verification of Operational Status	The Source will maintain documentation to verify that the Method 22 has been performed while the system is in operation.	The pressure measurement system will alert the operator if the system is not functioning properly.
c. QA/QC Practices and Criteria	Certification is not required for Method 22 observations, but personnel shall be trained in general procedures for the determination of visible emissions. Persons performing visible emission observations shall be trained in determining the presence of visible emissions. A list of observers trained to perform the visible emission observations shall be maintained.	The pressure monitors will be calibrated maintained, and operated according to manufacturer's specifications. Documentation of all required calibrations and maintenance in accordance with these specifications shall be maintained by the Source.
d. Monitoring Frequency	Monthly	Daily
e. Data Collection Procedures	The EPA Reference Method 22 procedures shall be followed.	The pressure monitors will report on a daily basis to the operator via digital or analog signal. The data will be logged.
f. Averaging Time	N/A	N/A

I.III. Justification

I.III.1. Background

I.III.1.i. The pollutant specific emission unit is a coal processing building which houses two coal crushers. The building is equipped with a baghouse to control particulate matter emissions.

I.III.1.ii. Particulate matter removal is accomplished by passing the particulate laden gases through a porous fabric material. The solid particles buildup on the fabric surface

to form a thin porous layer of solids. This layer works in conjunction with the fabric material to trap the particulate matter.

I.IV. Rationale for Selection of Performance Indicators

I.IV.1. Monitoring of the baghouse operational parameters is intended to keep the baghouse operating within the manufacturer's specifications. Based on the manufacturer's guarantees and actual performance test data on these units, it can be concluded that when the baghouse emissions controls are operated as designed, particulate emissions are controlled to levels well below the applicable particulate emission standard. As such, the requirements of compliance assurance monitoring for particulate matter emissions from these units can be accomplished through the monitoring of the selected performance indicators. Monitoring these indicators will signal the potential need for corrective actions to avoid potential problems with any of these factors.

I.IV.2. Potential issues in the operation of a baghouse that can compromise its ability to effectively control particulate emissions can generally be categorized as issues with torn and/or broken bags or seals, and characteristics of the ash cake on the bags. The indicators described below were selected for their ability to provide an indication or warning of potential problems with any of these factors.

I.IV.2.i. Visible Emissions

(a) Based on the relationship between particulate matter in a particulate laden gas stream and opacity, an increase in opacity is a valid indication of increased particulate emissions due to compromised baghouse performance. Increased opacity emissions from typical levels, such as a sudden spike or a gradual increase are an indication that baghouse performance has decreased.

I.IV.2.ii. Differential Pressure

(a) The physical action of forcing particulate laden air through the baghouse filters causes a pressure drop of the gas stream. This differential pressure is indicative of normal operation of the baghouse when it remains in a specific range. If the pressure drops below the normal range, it could indicate a preferential pathway through the baghouse. If the pressure rises above the normal range, it could indicate that particulate cake has built up in the system which restricts flow and could cause issues in normal operation.

I.V. Rationale for Selection of Indicator Ranges

I.V.1. Visible Emissions

I.V.1.i. If the control device is operating properly, no visible emissions should be seen during the Method 22 test.

I.V.2. Pressure Differential

I.V.2.i. In the May 1, 2009 application to modify the Title V permit the Source submitted a CAM plan with respect to PM emission limitations for S102d. In the May 1, 2009 application, the Source proposed using differential pressure monitoring. Values outside of the normal operating range of 5 to 8 inches of water shall be cause for investigating the control device. This indicator range is the normal operating range for the baghouse as recommended by the operator.

J. Appendix J – Units 1 and 2 Wet Limestone SO_2 Scrubbers Compliance Assurance Monitoring Plan

J.I. Background

J.I.1. Emission Unit Description

J.I.1.i. Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

J.I.1.ii. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

J.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable SO_2 requirements:

J.I.2.i. Unit 1:

(a) 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV (Condition 1.2.3)

J.I.2.ii. Unit 2:

(a) 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV (Condition 2.2.3)

J.I.3. Monitoring Requirements:

J.I.3.i. Continuous SO_2 emissions monitoring.

J.I.4. Control Technology:

J.I.4.i. Units 1 and 2 are equipped with flue gas desulfurization devices (FGD – wet limestone scrubbers) to control SO_2 emissions.

J.II. Monitoring Approach

	Indicator 1
I. Indicator	SO_2 Emissions
Measurement Approach	SO_2 emissions will be monitored using a continuous emissions monitoring system (CEMS)

	Indicator 1
II. Indicator Range	An excursion is defined as any 30-day average of SO_2 emissions that exceed 0.11 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the wet scrubber performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	SO_2 emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	SO_2 emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in daily and 30-day rolling averages.

J.III. Justification

J.III.1. Background

J.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a wet scrubber to control SO_2 emissions. The scrubber also controls acid gas emissions to some extent; however, the control of acid gases was not the primary design consideration for the control device and CAM does not apply to those emissions.

J.III.1.ii. The limestone reacts with SO_2 in the exhaust gases to form calcium sulfate and calcium sulfite which becomes entrained in the gas stream to be captured by the downstream baghouse.

J.IV. Rationale for Selection of Performance Indicators

J.IV.1. Units 1 and 2 are equipped with SO_2 CEMS and are equipped with wet limestone scrubbers which are operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the SO_2 Regional Haze limits is acceptable monitoring for CAM.

J.V. Rationale for Selection of Indicator Ranges

J.V.1. Ongoing monitoring with the CEMS for Units 1 and 2 which shows emissions below the applicable standards presumes continued and successful operation of the wet scrubbers.

K. Appendix K – Unit 3 Lime Spray Dryer SO_2 Compliance Assurance Monitoring Plan

K.I. Background

K.I.1. Emission Unit Description

K.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

K.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable SO_2 requirements:

K.I.2.i. Unit 3:

(a) 0.20 lb/MMBtu heat input, daily average, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.1);

(b) 80% reduction of potential combustion concentration of SO_2, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.2);

(c) 2,125 tons of SO_2 per year, Colorado Construction Permit 12MF322-1 (Condition 3.2.1.3);

(d) 0.4 lb/MMBtu heat input 3-hour rolling average, Colorado Regulation No. 1, Section VI.B.4. (Condition 3.2.3);

(e) 0.15 lb/MMBtu heat input, 30-day rolling average, Colorado Regulation No. 23, Section IV.B (Condition 3.2.4);

(f) As applicable, the Source shall not emit into the atmosphere any gases which contain SO_2 emissions in excess of either (40 CFR Part 60, §60.43Da(a) (Condition 3.2.2):

(i) 520 ng/J (1.2 lb/MMBtu) heat input and 10 percent of potential combustion concentration (90 percent reduction) (40 CFR Part 60, §60.43Da(a)(1));

(ii) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

(iii) 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

(iv) 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

K.I.3. Monitoring Requirements:

K.I.3.i. Continuous SO_2 emissions monitoring.

K.I.4. Control Technology:

K.I.4.i. Unit 3 is equipped with a flue gas desulfurization device (FGD – lime spray dryer) to control SO_2 emissions.

K.II. Monitoring Approach

	Indicator 1
I. Indicator	SO_2 Emissions
Measurement Approach	SO_2 emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of SO_2 emissions that exceed 0.15 lb/MMBtu or any daily average of SO_2 emissions that exceeds 0.20 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the lime spray dryer performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	SO_2 emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous
e. Data Collection Procedures	SO_2 emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in daily and 30-day rolling averages.

K.III. Justification

K.III.1. Background

K.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a lime spray dryer to control SO_2 emissions. The spray dryer also controls acid gas emissions to some extent; however, the control of acid gases was not the primary design consideration for the control device and CAM does not apply to those emissions.

K.III.1.ii. The lime reacts with SO_2 in the exhaust gases to form calcium sulfate and calcium sulfite which becomes entrained in the gas stream to be captured by the downstream baghouse.

K.IV. Rationale for Selection of Performance Indicators

K.IV.1. Unit 3 is equipped with an SO_2 CEMS and is equipped with a lime spray-dryer which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the SO_2 BACT and Regional Haze limits are acceptable monitoring for CAM.

K.V. Rationale for Selection of Indicator Ranges

K.V.1. Ongoing monitoring with the CEMS for Unit 3 which shows emissions below the applicable standards presumes continued and successful operation of the lime spray-dryer.

L. Appendix L – Unit 2 SCR Compliance Assurance Monitoring Plan

L.I. Background

L.I.1. Emission Unit Description

L.I.1.i. Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

L.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable NO_x requirements:

L.I.2.i. Unit 2:

(a) 0.08 lb/MMBtu, 30-day rolling average, Regional Haze, Colorado Regulation No. 23, Section IV (Condition 2.3.3)

L.I.3. Monitoring Requirements:

L.I.3.i. Continuous NO_x emissions monitoring.

L.I.4. Control Technology:

L.I.4.i. Unit 2 is equipped with a selective catalytic reduction system for control of NO_x emissions.

L.II. Monitoring Approach

	Indicator 1
I. Indicator	NO_x Emissions
Measurement Approach	NO_x emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of NO_x emissions that exceed 0.08 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the SCR performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	NO_x emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous

	Indicator 1
e. Data Collection Procedures	NO_x emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in 30-day rolling averages.

L.III. Justification

L.III.1. Background

L.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a selective catalytic reduction system to control NO_x emissions.

L.III.1.ii. NO_x emissions are chemically reduced to N_2 and H_2O using ammonia injected into the exhaust stream. The reaction is aided by flowing the gas stream through a catalyst. Over time, the catalyst becomes plugged and degraded and requires replacement.

L.IV. Rationale for Selection of Performance Indicators

L.IV.1. Unit 2 is equipped with a NO_x CEMS and is equipped with a SCR system which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the NO_x Regional Haze limits are acceptable monitoring for CAM.

L.V. Rationale for Selection of Indicator Ranges

L.V.1. Ongoing monitoring with the CEMS for Unit 2 which shows emissions below the applicable standards presumes continued and successful operation of the SCR.

M. Appendix M – Unit 3 SNCR Compliance Assurance Monitoring Plan

M.I. Background

M.I.1. Emission Unit Description

M.I.1.i. Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler. Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization.

M.I.2. Emission Limitations and Regulations

The following includes all 40 CFR Part 64 applicable NO_x requirements:

M.I.2.i. Unit 3:

(a) 0.28 lb/MMBtu, 30-day rolling average, Regional Haze, Colorado Regulation No. 23, Section IV.B (Condition 3.3.4)

M.I.3. Monitoring Requirements:

M.I.3.i. Continuous NO_x emissions monitoring.

M.I.4. Control Technology:

M.I.4.i. Unit 3 is equipped with a selective non-catalytic reduction system for control of NO_x emissions.

M.II. Monitoring Approach

	Indicator 1
I. Indicator	NO_x Emissions
Measurement Approach	NO_x emissions will be monitored using a continuous emissions monitoring system (CEMS)
II. Indicator Range	An excursion is defined as any 30-day average of NO_x emissions that exceed 0.28 lb/MMBtu. When this occurs, the Source shall conduct an investigation of the SNCR performance. Records of the investigation and any maintenance activities or corrective actions conducted shall be recorded by the plant and made available to the Division upon request.
III. Performance Criteria	
a. Data Representativeness	NO_x emissions are measured at the stack outlet.
b. Verification of Operational Status	Operational status shall be demonstrated through the continuous process on/off signal recorded by the Data Acquisition and Handling System (DAHS).
c. QA/QC Practices and Criteria	The CEMS equipment and data quality assurance is in conformation with the applicable requirements in 40 CFR Parts 60 and 75.
d. Monitoring Frequency	Continuous

	Indicator 1
e. Data Collection Procedures	NO_x emission measurements will be performed in accordance with the requirements in 40 CFR Part 75. The emissions data will be stored in the unit's DAHS.
f. Averaging Time	CEMS data shall be reduced to 1-hour averages as required by 40 CFR Part 75. The 1-hr averages shall be used in 30-day rolling averages.

M.III. Justification

M.III.1. Background

M.III.1.i. The large pollutant specific emission unit is a coal fired boiler which burns natural gas for startup, shutdown and/or flame stabilization. The boiler is equipped with a selective non-catalytic reduction system to control NO_x emissions.

M.III.1.ii. NO_x emissions are chemically reduced to N_2 and H_2O using ammonia injected into the exhaust stream.

M.IV. Rationale for Selection of Performance Indicators

M.IV.1. Unit 3 is equipped with a NO_x CEMS and is equipped with a SNCR system which is operated in a manner consistent with safety and good air pollution control practices for minimizing emissions. The Division considers that monitoring compliance with the NO_x Regional Haze limits are acceptable monitoring for CAM.

M.V. Rationale for Selection of Indicator Ranges

M.V.1. Ongoing monitoring with the CEMS for Unit 3 which shows emissions below the applicable standards presumes continued and successful operation of the SNCR.

N. Coal Sampling Plan

Rev. 6 – 6/5/2020

Note: Tri-State G & T follows ASTM procedures for coal sampling, sample preparation and sample analyses. In general, Tri-State will endeavor to use the latest revisions of the appropriate ASTM procedures for the equipment in use.

N.I. Coal Sampling

N.I.1. Background

Craig Station operates and maintains three coal sampling systems: A2, A3 and B3. Two of the systems (A3 and B3) are “As Fired” systems that are utilized to sample the day's coal burn in each of the three boilers. The “As Fired” sample results may be used to calculate the potential combustion concentration, or average inlet emission rate, of sulfur dioxide derived from the burning of coal in the boilers. This coal sampling plan therefore, describes the sampling, analysis and data management for the "As Fired” Samples.

Coal is delivered to Craig Station by truck and train. Each delivery is processed through the station's coal handling system. Coal from any delivery system can be used in any one, or all three, of the station's coal fired boilers.

N.I.2. A3 - As Fired Sampling System

This sampling system is located on A5 conveyor system that sends coal to the coal storage bunkers of each unit for firing the boilers Coal is delivered to this system from the coal yard. It may be coal from a single source or a combination of sources. It is referred to as the A3 Sampling System because it samples coal that is weighed by scales located on the A3 conveyor system.

N.I.3. B3 - As Fired Sampling System

This sampling system is located on B5 conveyor system that sends coal to the coal storage bunkers of each unit for firing the boilers. Coal is delivered to this system from the coal yard. It may be coal from a single source or a combination of sources. It is referred to as the B3 Sampling System because it samples coal that is weighed by scales located on the B3 conveyor system.

N.I.4. Coal Sampler Operation And Maintenance

All of the station coal samplers are set up and operated using the practices defined in ASTM D2234-99, Standard Practice for Collection of a Gross Sample of Coal.

Coal Handling Operators monitor the coal sampler operation. When the Samplers are in-service they discharge samples into heavy plastic bags attached to the sampler discharge. When the sampling is complete the Operator seals the sample bag, weighs the total sample, and labels each sample bag. The sample label identifies the Date, Belt, Sample Weight, Ending Tonnage, Number of Sample Bags, and the Operator's Name. The Operator then transfers the sealed and labeled sample bags to a protective container in a secured area to await pickup by a Laboratory Technician.

N.II. Sample Preparation and Laboratory Analyses

N.II.1. Sample Pickup and Preparation

Laboratory Technician retrieves the coal samples from the protected storage, checks the sample bags for damage, checks the labeling and rechecks the sample weight. The Technician then moves the samples to the Coal Preparation Laboratory where they are logged into the laboratory operation. Each sample is assigned a Laboratory Number and Sample ID. The Technician records this information, the Sample Weight and the Technician's name on the Fuels Analysis Sample Prep Log Sheet.

The Technician prepares the samples for analysis in the Coal Preparation Laboratory in accordance with ASTM 2013-00, Standard Method of Preparing Coal Samples for Analysis.

N.II.2. Coal Preparation Laboratory Sample Analyses

The Technician analyzes the samples for moisture using the procedures defined in ASTM D3302-00a, Standard Test Method for Total Moisture in Coal.

N.II.3. Main Chemistry Laboratory Sample Analyses

The 60 mesh samples prepared in the Coal Preparation Laboratory are taken to the Main Chemistry Laboratory where they are analyzed as described in the ASTM procedures as cited below.

N.II.3.i. ASTM D3173-00, Standard Test Method for Moisture in the Analysis Sample of Coal and Coke

N.II.3.ii. ASTM D5865-00, Standard Test Method for Gross Calorific Value of Coal and Coke

N.II.3.iii. ASTM D3174-00, Standard Test for Ash in the Analysis Sample of Coal and Coke from Coal

N.II.3.iv. ASTM D4239-00, Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High-Temperature Tube Furnace Combustion Methods

N.II.4. Laboratory Data Management

Laboratory data and results from the sample analyses for moisture, calorific value, ash and sulfur are entered and maintained in the Tri-State G & T Fuels Data Management System. The tonnage from vendor coal deliveries and daily coal burns are also maintained within the data management System.

N.III. Chain-Of-Custody Method

N.III.1. The sample chain-of-custody begins with each of the coal sampling systems described above. Prior to starting a sampling system, the Coal Board Operator identifies the origin of the coal to be sampled. This information is noted on sample identification labels. The sampling process is started and the Coal Handling Operator monitors the sampler system until sampling is complete.

N.III.2. When the sampling is completed the Coal Handling Operator seals the sample bags and labels the sample bags with the following information: Date, Belt, Sample Weight, Ending Tonnage, Number of Sample Bags, and the Operator's Name. The samples are then placed in a secure and protected location until a Laboratory Technician retrieves them.

N.III.3. When a Laboratory Technician retrieves the samples from the sampler area, and moves them to the Coal Preparation Laboratory, they are logged into the laboratory operation. Each sample is assigned a Laboratory Number and Sample ID. The Technician records this information along with Sample Weight and the Technician's name on the Fuels Analysis Sample Prep Log Sheet. This process identifies the sample label information as well as who is now handling the samples in the Coal Preparation Laboratory.

N.III.4. When the prepared samples are moved to the Main Chemistry Laboratory for analysis, they are transferred in sealed sample bottles labeled with the Sample ID. In the Main Laboratory the samples are analyzed according to the Sample ID and the names of the Technician(s) performing the analyses are noted on the Fuels Analysis Sample Prep Log Sheet.

N.III.5. The Technician who enters the laboratory data and results from the sample analyses into the Tri-State G & T Fuels Data Management System enters their name as Data Entry Technician on the Fuels Analysis Sample Prep Log Sheet.

N.IV. Coal Shipment and Sample Analysis Records

N.IV.1. Coal shipment and sample analysis records are maintained by the TriState G & T Craig Station and are available for review by the Division upon request. Craig Station maintains paper copies of the records for one year. The records are also kept electronically in Tri-State G & T's Fuels Data Management System.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-74:
March 2025 Field Inspection Report

COLORADO
Department of Public Health & Environment

Air Pollution Control Division
Field Inspection Report

DP
APCD RECEIVED 4/28/2025

COUNTY NUMBER: **081** SOURCE NUMBER: **0018**

DATE OF INSPECTION: **March 25, 2025** DATE REPORT SUBMITTED: **April 28, 2025**

COUNTY: **Moffat** INSPECTOR: **Christopher S. Reinhardt**

COMPANY: **Tri-State Generating and Transmission, Inc. – Craig Generating Station**

SITE LOCATION: **Craig Station 2101 South Ranney, Craig, Colorado 80234**

MAILING ADDRESS: **PO Box 33695, Craig, Colorado 80234**

CONTACT PERSON: **Brian Massengale** TIME: **9:00 AM**

TELEPHONE NO.: **720-539-0155** EMAIL: **bmassengale@tristategt.org**

PERMIT NO.: **96OPMF155**

SOURCE CLASS: Major ☒ SM-80 ☐ Syn Minor ☐ Minor ☐

INSPECTION TYPE: Full Compliance Evaluation ☒ Onsite Evaluation ☒
Partial Compliance Evaluation ☐ Offsite Evaluation ☐

Additional Inspection Records in File? Yes ☒ No ☐

HOURS: Travel & Prep: **30.0** Inspection: **3.0** Report: **17.0** Total: **50.0**

COMPLIANCE STATUS: IN COMPLIANCE ☐ OUT OF COMPLIANCE ☒

INTRODUCTION

An on-site full compliance inspection of the Tri-State Generation and Transmission Association, Inc. (Tri-State) – Craig Generating Station (Craig) coal fired boiler electricity generation facility located at 2101 S. Ranney, Craig, Moffat County, Colorado was conducted on March 25, 2025. Mr. Christopher S. Reinhardt, Field Enforcement Inspector for the Air Pollution Control Division (Division) contacted Mr. Brian Massengale, Senior Engineer, Environmental Services for Tri-State and scheduled the inspection. Mr. Massengale, Ms. Judy Thomas, Environmental Supervisor for Tri-State, Ms. Brenda Hershiser, Environmental Coordinator for Tri-State, Mr. Daniel Salgado, Senior Manager Air Quality for Tri-State, Mr. Stan Darveau, Operations Supervisor for Tri-State and Mr. Marc Mayzes, Senior Environmental Planner for Tri-State for Tri-State were present for the inspection. Mr. Massengale, Mr. Darveau, Ms. Thomas, and Ms. Hershiser provided a tour of the facility and process and production information to demonstrate compliance with Operating Permit 96OPMF155 Renewal 1, issued on July 1, 2021. Mr. Michael Kirby, CEMS Specialist for Tri-State was also present during portions of the inspection.

Source is in compliance with the permit expiration and renewal provisions of the General Permit Conditions of Operating Permit 96OPMF155. Operating Permit 96OPMF155 was renewed on July 1, 2021. A renewal Application will be due no later than July 1, 2025.

Craig Station is a coal-fired power plant with a total net electric generating capacity of ~1,303 megawatts from three individual combustion units. Units 1 and 2 each have a combustion design rating of 4,318 MMBtu/hour

each, and each unit has a net electrical generation capacity of 428 megawatts. Unit 1 began operating in 1980 and Unit 2 began operating in 1979. Unit 3 has a combustion design rating of 4,600 MMBtu/hour and a net electrical generation capacity of 447 megawatts. Unit 3 began operating in 1984. Units 1 and 2 originally were equipped with hot-side electrostatic precipitators (ESPs) to control PM emissions and wet limestone scrubbers to control SO_2 emissions; the Unit 1 and 2 ESPs were replaced with fabric filter baghouses in October 2003 and April 2004 respectively, at which times both units' wet scrubbers were upgraded and low NOx burners with over-fire air were added. Unit 3 is equipped with a baghouse to control PM emissions and a spray dryer scrubber to control SO_2 emissions. All three units are equipped with low-NOx burners with over-fire air to control NOx emissions and can use natural gas, propane, or fuel oil for start-up, shutdown, and flame stabilization. Unit 2 is equipped with Selective Catalytic Reduction (SCR) System for control of NOx that commenced operation in December 2017 to meet Regional Haze requirements. Unit 3 is equipped with a Selective Non-Catalytic Reduction (SNCR) System for control of NOx that commenced operation in December 2017 to meet Regional Haze requirements. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for NOx limits effective January 1, 1997. Additional activities permitted to emit air pollution at the Craig facility include three evaporative water cooling towers (one for each unit), coal handling systems, ash handling systems, limestone and lime handling systems, a waste ash staging area and landfilling activities. Tri-State also indicated that an auxiliary boiler exists at the facility which is not connected to fuel lines and has not been operational for many years.

Unit 3 underwent a capacity increase project; the existing turbine generator was enhanced, allowing the unit to generate about 30 more megawatts than it could previously. Associated auxiliary equipment was enhanced. The project is permitted under PSD Permits 12MF322-1, 12MF322-2, 12MF322-3, 12MF322-4 and 98MF0141. The project was completed May 2009. Operating Permit 96OPMF155 with renewal on July 1, 2021 now covers Unit 3 operations and its associated equipment.

Boral Material Technologies, Inc. (Boral) which is also located at the facility owned and operated a fly ash transfer and loading area and equipment which was used to pneumatically transfer fly ash from trucks to rail (AIRS Point 048). The equipment was rarely used as demand for railcar fly ash was low and had not been used at all for several years. This equipment operated under Operating Permit 10OPMF367.CN. Operating Permit 10OPMF367.CN was cancelled effective June 16, 2021 and is not addressed in this inspection. The remaining flyash handling activities conducted by Boral are covered under Operating Permit 96OPMF155.

This compliance evaluation is focused on the time period of February 2024 – January 2025 ("inspection period").

POINT AIRS ID/PERMIT NUMBERS

The following points are covered by Operating Permit 96OPMF155, Issued July 1, 2021: (February 2024 – January 2025)

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
Unit 1 Boiler	B001	001	S001	Unit 1 – Coal-fired boiler: Babcock & Wilcox #NB24157, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	10MF579	Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air
Unit 2 Boiler	B002	002	S002	Unit 2 – Coal-fired boiler: Babcock &Wilcox #NB24156, 4318 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization		Baghouse Wet SO_2 scrubber Low-NO_x burners with overfire air SCR
Unit 3 Boiler	B003	003	S003	Unit 3 – Coal-fired boiler: Babcock & Wilcox #NB24602, 4600 MMBtu/hour, pulverized-coal dry-bottom boiler Natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization	12MF322-1	Spray dryer Baghouse Low-NO_x burners with overfire air SNCR
Coal Handling – Units 1 & 2	P101	004	F101a	Coal hauling – Units 1 & 2	11MF276	$MgCl_2$, water, or equivalent application, as necessary
			F101b	Coal unloading to grizzly – Units 1 & 2		Water spray with surfactant, as necessary
			F101c	Coal surge pile		Water with surfactant, as necessary
			S101d	Primary coal crushing – Units 1 & 2		Baghouse
			S101e	Secondary coal crushing building – Units 1 & 2		Baghouse
			S101f	Common coal transfer building belt A		Baghouse
			S101g	Common coal transfer building belt B		Baghouse
			S101h	Coal stackout building – Units 1 & 2		Baghouse
			F101i	Coal stackout – Units 1 & 2		Telescopic chute
			F101j	Coal storage piles – Units 1 & 2		Water spray prior to stackout, as necessary
			S101k	Coal reclaim A – Units 1 & 2		Baghouse
			S101l	Coal reclaim B – Units 1 & 2		Baghouse
			S101m	Coal tripper deck & silos – Units 1 & 2		Baghouse

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
Ash Handling – Units 1 & 2	P203	016	S203a	Ash storage silo A – Units 1 & 2	11MF332	Baghouse (Shared with S203e)
			S203b	Ash storage silo B – Units 1 & 2		Baghouse (Shared with S203d)
			F203c	Ash truck loading – Units 1 & 2		Low dust unloading system
			S203d	Silo B dry ash unloading – Units 1 & 2		Baghouse (Shared with S203b)
			S203e	Silo A dry ash unloading – Units 1 & 2		Baghouse (Shared with S203a)
Limestone Handling – Units 1 & 2	P201	020	F201a	Limestone hauling	11MF415	Paved portions of road
			S201b	Limestone truck unloading		Baghouse
			S201c	Limestone silo #1 – Units 1 & 2		Baghouse
			S201d	Limestone silo #2 – Units 1 & 2		Baghouse
Coal Handling – Unit 3*	P102*	023	F102a	Coal train unloading – Unit 3	12MF322-2	Water spray
			S102b	Coal conveyor portal building – Unit 3		Baghouse
			S102c	Coal conveyor portal building – Unit 3		Baghouse
			S102d	Secondary coal crushing (2 crushers) – Unit 3		Baghouse
			S102e	Coal stackout building – Unit 3		Baghouse
			F102f	Coal stackout – Unit 3		Telescopic chutes
			F102g	Coal storage pile – Unit 3		PM control plan, including compaction, chemical use or watering, as necessary
			S102h	Coal reclaim system – Unit 3		Baghouse
			S102i	Coal tripper deck & silos – Unit 3		Baghouse
			S102j	Loadout coal to railcars – Unit 3		Baghouse
			S102k	Common coal transfer building extension		Baghouse
			F102l	Coal train loading		None
Ash Handing – Unit 3	P204	032	S204a	Ash storage silo – Unit 3	12MF322-3	Baghouse
			F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3		Low dust loader (wet ash) Baghouse (dry flyash)
			S204c	Recycle ash tank		Baghouse
			F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3		$MgCl_2$ application on roads, as necessary
Lime Handling	P202	035	F202a	Lime hauling	12MF322-4	Paved portions of road
			S202b	Lime unloading		Baghouse

Emission Unit	Facility ID	AIRS ID	Facility Stack ID	Description	Colorado Construction Permit	Pollution Control
and Storage – Unit 3			S202c	Lime conveying and silo		Baghouse
			S202d	Lime day bin		Baghouse
Cooling Towers – Units 1 & 2	P401	040	S401	Cooling tower – Unit 1, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-197-74, ten cells with BACT compliant drift eliminators	96MF195	Drift eliminators
	P402		S402	Cooling tower – Unit 2, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6516-12-209-74, ten cells with BACT compliant drift eliminators		Drift eliminators
Unit 3 Cooling Tower	P403	044	S403	Cooling tower – Unit 3, Make: Marley, Model: Class 600 Crossflow / 6516-4-10, Serial #: 6517-12-29-79, ten cells with BACT compliant drift eliminators	98MF0141	Drift eliminators
Emergency Diesel Fire-Pump Engine	N/A	N/A	N/A	Emergency diesel fire-pump engine, Make: Caterpillar, Model: 3306 D, Serial #: 64Z15539, 302 horsepower	N/A	None
Units 1&2 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Detroit Diesel, Model: 9123-7305, SN: 12E-4581, 1048 horsepower	N/A	None
Unit 3 Emergency Diesel Generator	N/A	N/A	N/A	Emergency diesel generator, Make: Caterpillar, Model: 3412, SN: 38S11242, 545 horsepower	N/A	None

*Note that the Unit 3 coal handling system is occasionally used to blend coal for Units 1 and 2

SOURCE COMPLIANCE HISTORY

- Sierra Club v. Tri-State et al., Civil Action No 96-N-2368 - Litigation initiated by the Sierra Club Inc. in 1996 alleged that Tri-State violated State and Federal laws related to opacity limits and failed to operate the facility consistent with good air pollution control practices from 1991 through 1996. A Consent Decree, signed by both parties on March 19, 2001, identified the specific issues, timelines for corrective actions, and consequences for continued non-compliance. The Consent Decree required Tri-State to construct baghouses to replace the electrostatic precipitators on Units 1 and 2 by December 31, 2003 (Unit 1) and June 30, 2004 (Unit 2). Compliance testing performed January 13, 2004 on Unit 1 indicated an average PM emission rate 0.006 lb/mmBtu, in compliance with that Unit's 0.03 lb/mmBtu emission limit. Compliance testing performed July 13, 2004 on Unit 2 indicated an average PM emission rate 0.005 lb/mmBtu, in compliance with that Unit's 0.03 lb/mmBtu emission limit. Tri-State is classified as a major emission source of air pollution for both PSD and Title V permitting applicability.

For Boilers 1 and 2, their cooling towers and associated coal, limestone and ash handling, Title V Operating Permit 96OPMF155 was issued May 1, 2005 which replaced PSD Permits 10MF579, 11MF276, 11MF332, 11MF415, 11MF994F and Construction Permits 96MF195, and 01MF0003. Boiler 3, its cooling tower and associated coal, limestone and ash handling are subject to PSD Permits 12MF322-1, 2, 3, and 4 and Construction Permit 98MF0141. The 130 mmBtu/hr auxiliary boiler at the facility, which was in service at the time, was subject to PSD Permit 12MF322-1A. The aux boiler and its associated permit are no longer active. Furthermore, the Consent Decree was terminated in 2006.

- Case 2011-003: The Division alleged numerous compliance issues with a stack test program and alleged a PM emissions exceedance. The Division questioned the probe and filter temperatures for particulate testing and Orsat results. Tri-State questioned the use of Method 202 for determining PM_{10} emissions claiming Method 201A should be used instead. The enforcement action was closed by means of a No Further Action Letter dated May 27, 2011.

- A 2012 inspection by the Division found the facility out of compliance for various excess SO_2 emissions events which occurred on October 15, 2011 – October 16, 2011. The issues were resolved by means of a Verbal Warning.

- A 2014 inspection by the Division found the facility out of compliance for having emissions in excess of an applicable SO_2 and opacity limit during the inspection period. The issues were resolved by means of a Verbal Warning.

- A 2016 inspection reported Tri-State Craig Station was determined to be out of compliance with Construction Permit No. 12MF322-1 for having three hours in which Unit 3 operated with emissions in excess of the 0.4 lb/MMBtu (three hour rolling average) SO_2 emission limit. All excess emissions were determined to be caused by a valid malfunction or startup event pursuant to the Affirmative Defense Provisions of the Colorado AQCC Common Provisions Regulation. Craig Station was found to be in compliance with all other applicable Operating Permits, Construction Permits, and AQCC Regulations. Enforcement discretion was advised, and thus, enforcement was not recommended.

- A 2018 inspection reported that Tri-State Craig Station was determined to be out of compliance for exceeding opacity limits for the Unit #2 Boiler, as the result of a valid malfunction, failed to accurately calculate fugitive emissions, resulting from a misunderstanding regarding whether Tri-State or Boral was required to calculate fugitive emissions for a 300 foot section of road used by Boral to haul ash at the facility, and failed to submit self-certification by the specified deadline for the Unit #3 Boiler, resulting from the steam turbine failing and requiring repair. The Affirmative defense was granted for the opacity exceedances, and enforcement discretion was granted for failing to correctly calculate fugitive emissions and failing to submit self-certification by the specified deadline. No enforcement was pursued.

- A 2019 inspection reported that Tri-State Craig Station was determined to be out of compliance for exceeding opacity limits, as the result of a valid malfunction, and for fugitive dust emissions for the ash handling system, as the result of a valid malfunction. The affirmative defense was granted for both non-compliance issues and no enforcement was pursued.

- A 2021 inspection reported that Tri-State was determined to be out of compliance for exceeding opacity limits, as the result of a valid malfunction, and failed to conduct a boiler tune-up on the #2 Boiler by the specified deadline as required by MACT Subpart UUUUU, as a result of COVID-19 restrictions. The opacity exceedance occurred as the result of a valid upset and qualified for the affirmative defense from enforcement which was granted, and the Division provided enforcement discretion regarding the late #2 Boiler tune up as it was the result of restrictions related to the COVID-19 Pandemic. No enforcement action was pursued.

- A 2022 inspection reported that Tri-State Craig Station was determined to be out of compliance for exceeding opacity limits as the result of valid malfunctions, exceeding BACT CO emissions limits as the result of a valid malfunction and submitting an Excess Emissions Report that did not include complete and accurate information. The opacity exceedances and CO exceedances were determined to be valid malfunctions, qualifying for the affirmative defense from enforcement. A Verbal Warning was issued on August 11, 2022 to resolve the incomplete and inaccurate Excess Emissions report after a complete and accurate revised report was submitted.

- A 2023 inspection reported that Tri-State Craig Station was determined to be out of compliance for

exceeding opacity limits as the result of valid malfunctions, exceeding the BACT SO2 limit for #3 Boiler as the result of a valid malfunction, and exceeding the mercury emissions limit for the #1 Boiler. The opacity exceedances and SO2 exceedance were determined to be valid malfunctions, qualifying for the affirmative defense from enforcement. A Verbal Warning was issued on June 22, 2023 to resolve non-compliance associated with the mercury emissions limit exceedance on the #1 Boiler.

- A 2024 inspection reported that Tri-State Craig Station was determined to be out of compliance for exceeding Unit 2 and Unit 3 opacity limits as the result of valid malfunctions, exceeding the Unit 3, pounds per million Btu, 3- hour rolling average SO2 emissions limit as the result of a valid malfunction. The report also indicated that Tri-State Craig Station was determined to be out of compliance for failing to conduct EPA Method 9 Readings as required on the S101e - Units 1 and 2 Secondary Coal Crushing Building Dust Collector as a result of the catching fire, and being taken out of service and the S101k - Units 1 and 2 Coal Reclaim A Dust Collector the result of mechanical failure of the unit and unavailability of parts to effect repairs. The violations for failing to conduct required Method 9 readings were resolved with enforcement discretion. Finally, the inspection reported that Tri-State Craig Station was determined to be out of compliance for failing to monitor emissions to mercury for Unit 3. A verbal Warning was issued on April 8, 2024 to resolve this violation. No additional enforcement action was pursued.

NSPS/NESHAP/MACT APPLICABILITY

New Source Performance Standards requirements of 40 CFR 60, Subpart D: Standards of Performance for Fossil Fuel Fired Steam Generators applies to Unit 1 and Unit 2 at the facility.

New Source Performance Standards requirements of 40 CFR 60, Subpart Da: Standards of Performance for Electric Utility Steam Generating Units applies to Unit 3 at the facility.

New Source Performance Standards requirements of 40 CFR Part 60, Subpart Y: Standards for Coal Preparation Plants apply to the F102a – Coal Train Unloading; S102b & S102c – Coal Conveyors; S102h – Coal Reclamation System; S102j – Coal Loadout to Railcars; and F102l – Coal Train Loading.

Maximum Achievable Control Technology requirements of 40 CFR 63, Subpart UUUUU ("MATS"): National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units applies to Unit 1, Unit 2 and Unit 3 at the facility. The rule, often called the Mercury and Air Toxics Standards, shall be referred to as "MATS" hereinafter.

REPORTS

Title V Semi Annual Monitoring Reports ("SAR")

Period	Due	Received
1/1/2024 – 6/30/2024	8/1/2024	7/18/2024
7/1/2024 – 12/31/2024	2/1/2025	1/28/2025

Except as noted below no deviations were reported for the period of January 1, 2024 through June 30, 2024. Deviations were reported for the period of July 1, 2024 through December 31, 2024. The source reported fugitive particulate emissions for the S203a Ash Storage Silo Units 1 and 2 Fly Ash Silo Unloading area which were determined to have occurred as the result of a valid upset. See Malfunction Section.

40 CFR 63.10010(h)(6)(i), 40 CFR 63.10010(h)(6)(ii), and 40 CFR 63.10020(d) require that Tri-State report as deviations any non-quality assurance/quality control related monitor downtime events. Tri-State reported periods of monitor downtime as deviations for the Units 1, 2 and 3 SO2 and Hg monitoring systems pursuant to these

requirements during the periods of January 1, 2024 through June 30, 2024 and July 1, 2024 through December 1, 2024. However, these deviations did not result in excessive monitor downtime for any of monitoring systems nor did these deviations result in any excess emissions.

The reports described above were certified by a responsible official in accordance with the provisions of General Permit Condition #2.a. Semi-Annual Monitoring Reports were submitted in accordance with the provisions of General Permit Condition #22(d).

Title V Annual Compliance Certifications ("ACC")

Period	Due	Received
1/1/2024 – 12/31/2024	2/1/2025	1/28/2025

The same deviations as were reported in Semi-Annual Monitoring a Deviation Report for the periods of January 1, 2024 through June 30, 2023 and July 1, 2023 through December 31, 2023 were reported in the Annual Compliance Certification for the period of January 1, 2023 through December 31, 2023. See Malfunction Section.

The reports described above were certified by a responsible official in accordance with the provisions of General Permit Condition #2.a. Annual Compliance Certifications were submitted in accordance with the provisions of General Permit Condition #2.

MACT/NSPS Reports

Excess Emissions Reports (EERs) are submitted to the Division for purposes of NSPS Subpart D and Da and MACT Subpart UUUUU. See EERs section below.

Excess Emissions Reports ("EERs")

Tri-State Craig Station Unit 1: Excess Emissions Reports			
Quarter	**Due**	**Received**	**Notes**
Q1-2024	5/1/2024	4/26/2024	No excess emissions or excessive downtime reported during the period.
Q2-2024	8/1/2024	7/30/2024	No excess emissions or excessive downtime reported during the period.
Q3-2024	11/1/2024	10/28/2024	No excess emissions or excessive downtime reported during the period.
Q4-2024	2/1/2025	1/28/2025	No excess emissions or excessive downtime reported during the period.

Tri-State Craig Station Unit 2: Excess Emissions Reports			
Quarter	**Due**	**Received**	**Notes**
Q1-2024	5/1/2024	4/26/2024	No excess emissions or excessive downtime reported during the period.
Q2-2024	8/1/2024	7/30/2024	No excess emissions or excessive downtime reported during the period.
Q3-2024	11/1/2024	10/28/2024	No excess emissions or excessive downtime reported during the period.
Q4-2024	2/1/2025	1/28/2025	No excess emissions or excessive downtime reported during the period.

Tri-State Craig Station Unit 3: Excess Emissions Reports			
Quarter	**Due**	**Received**	**Notes**
Q1-2024	5/1/2024	4/26/2024	No excess emissions or excessive downtime reported during the period.
Q2-2024	8/1/2024	7/30/2024	13.90% downtime reported for the Hg CMMS (see Condition 5.7.2). No excess emissions reported and no additional downtime in excess of 5% reported during the period.
Q3-2024	11/1/2024	10/28/2024	9.19% downtime reported for the Hg CMMS (see Condition 5.7.2). No excess emissions reported and no additional downtime in excess of 5% reported during the period.
Q4-2024	2/1/2025	1/28/2025	No excess emissions or excessive downtime reported during the period.

All Excess Emissions Reports were submitted to the Division in a timely manner.

40 CFR 63, Subpart UUUUU ("MATS")

Type	Due	Received
Initial Notification of Applicability	8/16/2012	7/31/2012

The following reports were submitted to EPA's Central Data Exchange via CEDRI. The Certification Date is considered the date received.

Unit #	Report	Certification Date	Notes
1	63.10031(f)(6) MATS Report	5/30/2024	Unit 1 PM LEE Test Report, 1/17/2024. Result 0.010 lb/mmBtu. Limit 0.030 lb/mmBtu
2	63.10031(f)(6) MATS Report	5/30/2024	Unit 2 PM LEE Test Report, 1/18/2024. Result 0.009 lb/mmBtu. Limit 0.030 lb/mmBtu
1	63.10031(f)(6) MATS Report	5/30/2024	MATS Quarterly Compliance Report, Unit 1 PM/SO_2/Hg CMS EER (1/1/2024 – 3/31/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
2	63.10031(f)(6) MATS Report	5/30/2024	MATS Quarterly Compliance Report, Unit 2 PM/SO_2/Hg CMS EER (1/1/2024 – 3/31/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
3	63.10031(f)(6) MATS Report	5/30/2024	MATS Quarterly Compliance Report, Unit 3 PM/SO_2/Hg CMS EER (1/1/2024 – 3/31/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
1	63.10031(f)(6) MATS Report	8/28/2024	MATS Quarterly Compliance Report, Unit 1 PM/SO_2/Hg CMS EER (4/1/2024 – 6/30/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
2	63.10031(f)(6) MATS Report	8/28/2024	MATS Quarterly Compliance Report, Unit 2 PM/SO_2/Hg CMS EER (4/1/2024 – 6/30/2024),

Unit #	Report	Certification Date	Notes
			No deviations reported excepting those due to monitor downtime (see (1) below).
3	63.10031(f)(6) MATS Report	8/28/2024	MATS Quarterly Compliance Report, Unit 3 PM/SO_2/Hg CMS EER (4/1/2024 – 6/30/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
3	63.10031(f)(6) MATS Report	8/28/2024	Unit 3 PM LEE Test Report, 6/15/2024. Result 0.004 lb/mmBtu. Limit 0.030 lb/mmBtu
1	63.10031(f)(6) MATS Report	8/28/2024	Annual RATA report - SO2 (HCl Surrogate) Monitoring (Pass) 6/10/2024
2	63.10031(f)(6) MATS Report	8/28/2024	Annual RATA report - SO2 (HCl Surrogate) Monitoring (Pass) 6/11/2024
3	63.10031(f)(6) MATS Report	8/28/2024	Annual RATA report - SO2 (HCl Surrogate) Monitoring (Pass) 6/13/2023 and 6/13/2024
1	63.10031(f)(6) MATS Report	8/29/2024	Annual RATA Report – Hg Monitoring (Pass) 6/10/2024
2	63.10031(f)(6) MATS Report	8/29/2024	Annual RATA Report – Hg Monitoring (Pass) 6/11/2024
3	63.10031(f)(6) MATS Report	8/29/2024	Annual Primary and Backup Hg Sorbent Trap RATAs – 6/13/2024 and 6/14/2024 – Pass both
1	63.10031(f)(6) MATS Report	11/22/2024	MATS Quarterly Compliance Report, Unit 1 PM/SO_2/Hg CMS EER (7/1/2024 – 9/30/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
2	63.10031(f)(6) MATS Report	11/22/2024	MATS Quarterly Compliance Report, Unit 2 PM/SO_2/Hg CMS EER (7/1/2024 – 9/30/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
3	63.10031(f)(6) MATS Report	11/22/2024	MATS Quarterly Compliance Report, Unit 3 PM/SO_2/Hg CMS EER (7/1/2024 – 9/30/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
1	63.10031(f)(6) MATS Report	2/12/2025	MATS Semi-Annual Compliance Report, Unit 1 PM/SO_2/Hg CMS EER (10/1/2024 – 12/31/2024), No deviations reported excepting those due to monitor downtime (see (1) below).
2	63.10031(f)(6) MATS Report	2/12/2025	MATS Quarterly Compliance Report, Unit 2 PM/SO_2/Hg CMS EER (10/1/2024 – 12/31/2024), No deviations reported excepting those due to monitor downtime (see (1) below).

Unit #	Report	Certification Date	Notes
3	63.10031(f)(6) MATS Report	2/12/2025	MATS Quarterly Compliance Report, Unit 3 PM/SO_2/Hg CMS EER (10/1/2024 – 12/31/2024), No deviations reported excepting those due to monitor downtime (see (1) below).

(1) 40 CFR 63.10010(h)(6)(i), 40 CFR 63.10010(h)(6)(ii), and 40 CFR 63.10020(d) require that Tri-State report as deviations any non-quality assurance/quality control related monitor downtime events. Tri-State reported periods of monitor downtime as deviations for the Units 1, 2 and 3 SO2 and Hg monitors pursuant to these requirements during the periods of January 1, 2024 through June 30, 2024 and July 1, 2024 through December 1, 2024. However, these deviations did not result in excessive monitor downtime for any of monitoring systems nor did these deviations result in any excess emissions.

APENS

APENs were submitted in accordance with the provisions of General Permit Condition 22(e).

AIRS Number	Description	Date Last APEN Was Received
001	Coal fired boiler - Unit 1	4/8/2024
002	Coal fired boiler - Unit 2	4/8/2024
003	Coal fired boiler - Unit 3	4/8/2024
004	Coal handling Units 1 and 2	4/8/2024
016	Ash handling Units 1 and 2	4/8/2024
020	Limestone handling Units 1 and 2	1/24/2025
023	Coal handling Unit 3	4/8/2024
032*	Ash handling Unit 3; haul road for ash and scrubber sludge Units 1, 2, 3	3/27/2023
035	Lime handling Unit 3	4/8/2024
040	Units 1 and 2 cooling towers	3/28/2022
044	Unit 3 cooling tower	4/26/2022
048**	Fly ash transfer and loading owned and operated by Boral Materials Technologies	NA Cancelled 6/16/2022

*Points 033 and 034 have been combined into Point 032.
**There is no further discussion of this point in this report. AIRS ID Point 048 was cancelled effective June 16, 2022.

APENs are due to the Division every 5 years barring any modification to the process or significant increase in emissions. All APENs are up to date.

MALFUNCTION REPORT REVIEW

8/16/2024, 10:30 – 11:30

Source claims upset due to the S203a Ash Storage Silo A knife gate and flow control valve being stuck in the open position because of debris such as a wire brush, webbing, welding rods, pipe valves, and chunks of solidified ash resulting fly ash escaping from the S203a Ash Storage Silo truck loading chute and in fugitive particulate emissions from the S203a Ash Storage Silo Units 1 and 2 Fly Ash Silo Unloading area violating Permit Condition 10.4.1 requiring that ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses.

Eco Material Technologies (Eco) which purchases flay ash form Tri-State operates the fly ash truck loading at the facility.

As soon as Tri-State became aware of this issue, Tri-State scrubber personnel put on appropriate respiratory gear entered the fly ash unloading room and closed the emergency Shutoff valve. The valve is located upstream of the knife gate and the flow control valve. The knife gate and flow control valve were found to be stuck open with debris. Eco then cleaned out the silo after being cleared to reenter the area and normal operations resumed that day.

While the unloading room was minimally affected by dust the truck load out drive-through building area has a small pile of 1-2 tons of fly ash. High winds dusted the area to the east of the silo, including C road. The dust issues on the roads were immediately taken care of with the water truck once the fly ash leak was secured. The scrubber cleaning crew was diverted to the drive-through for clean up as well.

The source reported that the prompt investigation, emergency shut off, and cleaning activities served to minimize dust emissions and potential impacts associated with the event. No EPA Method 9 Visible Emissions Observations were conducted related to the event, and Tri-State reported that no off property transport of visible emissions was observed during the event.

Plat Operations works to vacuum out hoppers following a compartment outage but cannot always ensure that foreign material remains clear of the feeders. During silo outages an inspection is performed to clean and remove any foreign objects from the unloading chutes. Most findings are from years of accumulation and are considered unavoidable.

The week following this incident, ECO personnel went through training and retraining on where the emergency shut-off valve is located and the emergency response and hazard communication plan. Part of this training included updating their phone numbers for Tri-State and understanding who to call if this reoccurs.

Tri-State also moved the controls for emergency shut-off valve to a more easily accessible location outside of the fly ash unloading room and added a screen in the duct to prevent debris from reach the knife gate and flow control valve.

This event which occurred on a Friday was reported by telephone as a malfunction on the next following business day Monday, August 19, 2024. A follow-up report was received by the Division on January 28, 2025. This event is considered to be a valid malfunction.

COMPLIANCE ASSISTANCE/SOURCE ACTIONS

None.

PERMIT CONDITIONS AND COMPLIANCE STATUS

This section follows the conditions of Operating Permit No. ***96OPMF155*** *issued to Tri-State on July 1, 2021. Inspector comments for each condition are marked in* ***bold font*** *for ease of identification. (February 2024 – January 2025)*

Section I - General Activities and Summary

1. Permitted Activities

1.1 The Tri-State Generation and Transmission Association Craig Station (herein, Source) is a coal-fired power plant with a total gross electric generating capacity of 1,375 MW. The facility operates consisting of three, pulverized coal, dry-bottom boilers: Units 1 and 2, rated at 4,318 MMBtu/hour each, were placed in service in 1980 and 1979, respectively; Unit 3, rated at 4,600 MMBtu/hour, was placed in service in 1984. All three units use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. Associated activities covered by the permit include three cooling towers, coal handling systems, ash handling systems, limestone handling systems, and lime handling systems.

Units 1 and 2 use limestone scrubbers to control SO_2 emissions; Unit 3 uses a lime spray-dryer scrubber to control SO_2 emissions. All three units use baghouses to control PM emissions, and low-NOx burners and overfire air (OFA) for NO_x emissions. Units 1 and 2 also use overfire air and related NO_x control upgrades; they are also subject to the requirements of special requirements from a 2001 revision to the Colorado State Implementation Plan. Unit 2 is equipped with a selective catalytic reduction (SCR) system, and Unit 3 is equipped with a selective non-catalytic reduction (SNCR) system for control of NO_x emissions to comply with the emission limits of the State of Colorado Regional Haze Program.

All three units are subject to the requirements of the Acid Rain Program.

The facility is located at 2101 S. Ranney Street, Craig, Colorado, Moffat County. The area in which the plant operates is designated as attainment for all criteria pollutants.

Wyoming is an affected state within 50 miles of the plant. There are two Federal Class I designated areas within 100 kilometers of the facility: Mount Zirkel National Wilderness Area and Flattops National Wilderness Area. Dinosaur National Monument is a Federal land area within 100 kilometers of the facility. Although it is not a Federal Class I area, Dinosaur has been designated by the State to have the same sulfur dioxide (SO_2) increment as a Federal Class I area.

1.2 Until such time as this permit expires or is modified or revoked, the Source is allowed to discharge air pollutants from this facility in accordance with the requirements, limitations, and conditions of this permit.

1.3 The Operating Permit incorporates the applicable requirements contained in the underlying construction permits, and does not affect those applicable requirements, except as modified during review of the application or as modified subsequent to permit issuance using the modification procedures found in Regulation No. 3, Part C. These Part C procedures meet all applicable substantive New Source Review requirements of Part B. Any revisions made using the provisions of Regulation No. 3, Part C shall become new applicable requirements for purposes of this Operating Permit and shall survive reissuance. This permit incorporates the applicable requirements (except as noted in Section II) from the following construction permits: 12MF322-1, 12MF322-2, 12MF322-3, 12MF322-4, 11MF415, 11MF332, 11MF276, 10MF579, 98MF0141, and 96MF195.

1.4 All conditions in this permit are enforceable by the United States Environmental Protection Agency (EPA), Colorado Air Pollution Control Division (hereinafter Division) and its agents, and citizens unless

otherwise specified. **State-only enforceable conditions are:** Permit Condition Number(s): Section II, Conditions 3.6.3; Section V, Conditions 3.g (last paragraph), 14 & 18.

1.5 All information gathered pursuant to the requirements of this permit is subject to the Recordkeeping and Reporting requirements listed under Condition 22 of the General Conditions in Section V of this permit.

No additional activities requiring a permit were observed during the inspection.

Source is in compliance.

2. Alternative Operating Scenarios (AOS)

2.1 There are no AOS associated with permitted activities at the facility.

Source is in compliance.

3. Prevention of Significant Deterioration (PSD)

3.1 This facility is located in an area designated attainment for all pollutants. It is categorized as a major stationary source (potential to emit $\geq$ 100 tons per year (tpy) for PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, and CO). Future modifications at this facility resulting in a significant net emissions increase (see Colorado Regulation No. 3, Part D, Sections II.A.27 and 44) for any pollutant as listed in Regulation No. 3, Part D, Section II.A.44 or a modification which is major by itself (i.e. a potential to emit $\geq$ 100 tpy of any pollutant listed in Regulation No. 3, Part D, Section II.A.44) may result in the application of the PSD review requirements.

3.2 There are no other Operating Permits associated with this facility for purposes of determining applicability of PSD regulations.

Craig Station is categorized as a major source for PSD provisions. Emissions have not increased such that a PSD modification has become required.

Source is in compliance.

4. Accidental Release Prevention Program (112(r))

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

The facility is subject to the Accidental Release Prevention Program.

Source is in compliance.

5. Compliance Assurance Monitoring (CAM)

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

Unit 1: PM (baghouse), SO_2 (wet scrubber)

Unit 2: PM (baghouse), NO_x (SCR), SO_2 (wet scrubber)

Unit 3: PM (baghouse), NO_x (SNCR), SO_2 (lime spray-dryer)

P102 – Coal Handling System, S102d – Secondary Coal Crushing Building: PM (baghouse)

The source is conducting the required monitoring under the CAM requirements. See condition 22.

Source is in compliance.

6. Summary of Emission Units

See Tables under the Point AIRS ID/Permit Number Section.

Source is in compliance.

Section II - Specific Permit Terms

1. Boiler B001 "Unit 1" – Coal-fired boiler, Babcock & Wilcox #NB24157, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	1.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 1.1
SO_2	1.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	1.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP) 0.28 lb/MMBtu 30-day rolling average (CO Reg. 23, IV.D.2.)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		4,065 tpy calendar year basis (CO Reg. 23, Section IV.D.3., see Condition 1.10) 0.46 lb/MMBtu calendar year average (see Acid Rain requirements in Section III)			
VOC & CO	1.4		See Condition 1.4	Recordkeeping and Calculation	Annually
Opacity	1.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, CO Reg. 6, Part A, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals
Coal Requirements	1.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	1.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 1.7	
NSPS D	1.8	See Condition 1.8			
CO SIP	1.9	See Condition 1.9			
Regional Haze	1.10	PM: 0.03 lb/MMBtu (See Condition 1.1)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		SO_2: 0.11 lb/MMBtu 30-boiler operating day rolling average (See Condition 1.2) NO_x: 0.28 lb/MMBtu (Condition 1.3) NO_x: 4,065 tpy (Condition 1.3)			
Acid Rain	0	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	1.12	See Condition 1.12 and 5			
CAM	1.13	See Condition 1.13			

Table 1 - Unit 1 Emissions and Requirements Summary

Unit 1 was operating during the inspection with the following emissions and operational parameters as provided by the DAHS.

Craig Station: Unit 1 Emissions and Operational Parameters (1-minute average) 10:00	
Load (gross MW)	162
Opacity of Emissions (%)	4.36(1)
CO2 (%)	7.2
Flow (scfh)	43,311,204
NOX (lb/MMBtu)	0.201
SO2 (lb/MMBtu)	0.022
SO2 Removal (%)	96.3(2)
Stack Temp (°F)	100.1

(1) Opacity was obtained from the monitor in the CEMS Shack at approximately the 11:00 hour.
(2) SO2 removal percentage was obtained from the scrubber control room reported as hourly data for the 11:00 hour.

Criteria pollutant emissions from Unit #1, as reported by Tri-State for calendar year 2024, are given in the table below. The permit imposes no annual mass emissions limits for Unit 1. Emissions factors shown are based on the burning of coal only. Tri-State also calculates and reports emissions from burning natural gas and fuel oil.

Tri-State G&T – Unit #1 Emissions Summary as Reported			
Pollutant	**Emissions Factor (uncontrolled)**	**2024 Emissions (tons/year)**	**Calculation Method**
PM (tons/year)	0.0100 lbs/mmBtu	93.4	2021 Stack Test
PM_{10} (tons/year)	0.0092 lbs/mmBtu	85.9	2021 Stack Test
SO_2 (tons/year)	NA	335.4	CEMS
NO_x (tons/year)	NA	2,176.6	CEMS

VOC (tons/year)	0.0002 lbs/mmBtu	1.9	1999 Stack Test
CO (tons/year)	0.5 lbs/ton coal	239.1	AP 42

1.1 Particulate matter (PM) emissions must not exceed the following limits:

1.1.1 0.10 lb PM/MMBtu heat input, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

1.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 1 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

1.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

1.1.2 0.03 lb PM/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3 0.03 lb PM/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

1.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 1.1.5.

1.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

1.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 1.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 1.13 (Colorado Regulation No. 23, Section V.B.1.).

1.1.4 0.03 lb PM/MMBtu heat input, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

1.1.5 To demonstrate compliance with the PM emission limits in Condition 1.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and conduct periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 1.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6, unless a PM_{10} emission factor was developed using source testing.

PM testing was conducted on January 18, 2024 with passing results as approved by the Division on February 26, 2024. Quarterly and tri-annual performance testing has shown compliance with the above-mentioned limits. The baghouse appears to be maintained in accordance with Section II, Condition 16.1. See inspector comments for Conditions 16.1 for further details. The source monitors opacity using continuous opacity monitoring. Given the low frequency of opacity exceedances, it can be assumed that the baghouse is operated in a manner consistent with good air pollution control practices. Tri-State calculates annual PM emissions and reports those emissions on annual APEN updates as required. See the table above for 2024 emissions calculations as reported by the source.

Source is in compliance with this condition.

1.2 **Sulfur dioxide (SO_2)** emissions must not exceed the following limits:

1.2.1 40 CFR Part 60, Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

1.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

1.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

The facility monitors compliance with the three-hour SO_2 emission limit using CEMS as required. The source reported no emissions in excess of 1.2 lbs/mmBtu heat input in any three hour period during the compliance period.

Source is in compliance with this condition.

1.2.2 1.2 lb/MMBtu heat input, three-hour rolling average, Colorado Regulation No. 1, Section VI.A.

1.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

1.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

The facility monitors compliance with the three-hour SO_2 emission limit using CEMS as required. The source reported no emissions in excess of 1.2 lbs/mmBtu heat input in any three hour period during the compliance period.

Source is in compliance with this condition.

1.2.3 0.11 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV. – Regional Haze and Colorado Regional Haze SIP

1.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 1.2.5.

1.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

1.2.3.3 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.4 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.2.3.3, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.5 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.2.3.6 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.2.3.3. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.2.3.7 The Source must maintain records and follow the reporting requirements as described in Condition 1.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

The facility monitors compliance with the 30-day rolling average SO_2 emission limit using CEMS. According to records provided by the facility, Unit 1 did not exceed this limit during this inspection period.

Source is in compliance with this condition.

1.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.2.4.1 The Source must treat one hundred percent (100%) of the flue gas from Unit 1 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 1.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

Note that in determining compliance with the requirements of Condition 1.2.4, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions.

1.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. 0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis;

b. 0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis.

1.2.4.3 SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 1.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 1.9;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

1.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 1.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

All exhaust gas from Unit 1 is treated by the wet flue gas desulfurization ("WFGD") unit to remove SO_2 and acid gasses prior to discharge into the atmosphere. The source reported that Unit 1 operated with no emissions in excess of any SO_2 limit for the compliance period, which indicates good air pollution control.

The facility monitors compliance with the 30-day SO_2 emission limit using CEMS. According to records provided by Tri-State, Unit 1 did not exceed this limit during this inspection period.

The facility monitors compliance with the 90-day SO_2 emission limit using CEMS. According to records provided by the facility, the unit did not exceed this limit during this inspection period.

The facility monitors compliance with the Unit 1 SO_2 reduction requirements using outlet CEMS and coal

analysis. According to records provided by the facility, the unit did not fail to meet 90% reduction requirement in any 90 day rolling average during this inspection period. During the inspection, the Unit 1 SO_2 removal rate was 96.3% as measured by the CEMS.

According to facility records, in no cases did the unit operate without achieving any SO_2 reduction during this inspection period.

Source is in compliance with this condition.

1.2.5 Compliance calculations for SO_2 requirements in Condition 1.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

1.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

1.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

1.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

Tri-State monitors emissions of SO_2 using a CEMS as required and calculates SO_2 emissions consistent with the specified methodologies above. Tri-State calculates annual SO_2 emissions and reports those emissions on annual APEN updates as required. See the table above for 2024 emissions calculations as reported by the source. Tri-State conducts operation and maintenance of the scrubber consistent with the requirements of Permit Condition 16.

Source is in compliance with this condition.

1.3 Nitrogen oxides (NO_x) emissions must not exceed the following limits:

1.3.1 40 CFR Part 60, Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

1.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat

input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

1.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

1.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

1.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

The facility monitors compliance with the rolling three-hour NO_x emission limit using CEMS as required. According to records provided by Tri-State, Unit 1 NO_X emissions did not exceed 0.7 lbs/mmBtu on a 3-hour rolling basis during the inspection period.

Source is in compliance with this condition.

1.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with NO_x in excess of 0.30 lb/MMBtu heat input on a calendar year annual average basis. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 1.7.

1.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

The facility monitors compliance with the annual NO_X limit using CEMS as required. According to facility records, there were no violations of the annual 0.30 lbs/MMBtu NO_X limit during the inspection period. Reported emissions for data year 2024 were 0.22 lb/MMBtu. The boiler is equipped with low-NOx burners utilizing two stage combustion with supplemental over fire air as required.

Source is in compliance with this condition.

1.3.3 0.28 lb/MMBtu, 30-day rolling average, Colorado Regulation No. 23, Section IV.D.2. – Regional Haze, as provided for in Condition 1.10

1.3.3.1 The Source must comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.2 At all times, the Source must maintain, calibrate, and operate a CEMS in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 1.3.3.1, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source must calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.3 In determining compliance with the NO_x regional haze limit, all periods of emissions must be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

1.3.3.4 For any hour in which fuel is combusted, the Source must calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 1.3.3.1. These hourly averages must be used to determine compliance in accordance with the averaging period, as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source must calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

1.3.3.5 Compliance shall be monitored using the CEMS as described in Condition 1.3.5.

1.3.3.6 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 1.10.5.

The facility monitors compliance with the 30-day rolling average NO_x emission limit using CEMS as required. According to records provided by Tri-State, Unit 1 NO_X emissions did not exceed 0.28 lb/MMBtu calculated on a 30-day rolling average during the inspection period.

Source is in compliance with this condition.

1.3.4 Craig Unit 1 must meet an annual NO_x limit of 4,065 tons per year by December 31, 2020 on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.)

The facility monitors compliance with the annual NO_X limit using CEMS. Annual NOx emissions for the 2024 calendar year was provided and is included in the table below.

Year	Reported Annual NOx Emissions (tons/yr)	*Annual NOx Emissions Limit (tons/yr)*
2024	2,176.6	*4,065*

Source is in compliance with this condition.

1.3.5 Compliance calculations for NO_x requirements in Condition 1.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 1.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

a. Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

1.3.5.2 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

Tri-State monitors emissions of NO_X using a CEMS as required and calculates NO_x emissions consistent with

the specified methodologies above.

Source is in compliance with this condition.

1.3.6 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 1.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

Tri-State calculates annual NO_x emissions and reports those emissions on annual APEN updates as required. See the table above for 2024 emissions calculations as reported by the source.

Source is in compliance with this condition.

1.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

1.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 1.6.1 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

Tri-State reports annual emissions from Unit 1 on APENs as required using the appropriate emissions factors listed in the permit and from 1999 stack test data. The permit imposes no annual mass emissions limits for VOC or CO. Annual SO_2 and NO_x emissions are measured using the CEMS as required. The permit imposes no annual NO_X or SO_2 mass emissions limits. See the table above §II, Condition 1.1 for annual emissions from data year 2024 as reported by Tri-State.

Source is in compliance with this condition.

1.5 Opacity

1.5.1 Colorado Regulation No. 1

1.5.1.1 Except as provided in Condition 1.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

1.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

Unit 1 is equipped with COMS to monitor opacity. Opacity of emissions in excess of any standard is reported on quarterly EERs as required. No exceedances of opacity limits were reported during the inspection period. The source was operating during the inspection and no visible emissions were observed. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 4.36%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

1.5.2 40 CFR Part 60, Subpart D

1.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

1.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

1.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 1.8.

Unit 1 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. The source was operating during the inspection and no visible emissions were reported. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 4.36%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

1.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

1.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

1.5.3.3 An opacity reading in excess of the limitations in Condition 1.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 1.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify

the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

1.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

Unit 1 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. The source was operating during the inspection and no visible emissions were reported. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 4.36%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

1.5.4 Compliance with the opacity emissions limitations in Condition 1.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4. (Colorado Regulation No. 3, Part C, Section V.C.5.)

1.5.4.1 The requirements for the COMS system are outlined in Condition 19.

1.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

Unit 1 is equipped with COMS as required. The source did not report any six-minute opacity averages in excess of the 20% opacity standard. Opacity in excess of any standard is reported on quarterly EERs as

required. The source was operating during the inspection and no visible emissions were reported. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 4.36%. Method 9 has not been utilized for compliance with opacity requirements. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

1.5.5 Partial streamlining of opacity limits into State Implementation Plan opacity limits – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS Subpart D (Conditions 1.5.1 and 1.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 1.5.3), except as follows:

1.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 1.5.1 and 1.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

1.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 1.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 1.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

Unit 1 is equipped with COMS to monitor opacity. Opacity of emissions in excess of any standard is reported on quarterly EERs as required. The source was operating during the inspection and no visible emissions were reported. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 4.36%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

1.6 Coal Requirements

1.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

1.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

Annual fuel consumption records are maintained as required. Actual fuel consumption by Unit 1 for Calendar year 2024 are shown in the table below. Belt scale calibration reports for 2024 were reviewed. Belt scales are calibrated at least annually as required. Coal samples are taken and analyzed daily. See inspector comments for Condition 20 for further details.

Tri-State G&T – Craig Station Unit 1 Fuel Use			
Year	**Coal Consumed (tons)**	**Fuel Oil Consumed (gallons)**	**Natural Gas Consumed (Mcf)**
2024	956,258	42,339	54,517
Limit:	*NA*	*NA*	*NA*

Source is in compliance with this condition.

1.7 Continuous Emissions Monitoring Systems (CEMS)

1.7.1 For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

1.7.2 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

Unit 1 is equipped with continuous Opacity, SO_2, NO_x, CO_2, Hg and Flow monitors as required. All CEMS equipment were reported to be operating appropriately during the inspection. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

1.8 40 CFR Part 60, Subpart D

1.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

1.8.2 In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

1.8.3 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

1.8.4 [Excess emissions reports] Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and monitoring system performance (MSP) report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

1.8.4.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

1.8.4.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 1.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

1.8.4.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 1.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

1.8.5 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

Unit 1 is equipped with continuous Opacity, SO_2 and NO_x monitors that conform to the requirement for 40 CFR Part 60 as required. Excess Emissions Reports are submitted as required. Tri-State did not report any exceedances of opacity limits nor, SO_2 or NO_x limits during the inspection period. Tri-State complies with the requirements of 40 CFR Part 60, Subpart A as required. See Conditions 18 and 19.

Source is in compliance with this condition.

1.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

1.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 1 in a manner consistent with good air pollution control practices for minimizing emissions.

1.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

1.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

1.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

1.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component, unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

No evidence was observed or discovered during the inspection to indicate that Tri-State is not operating and maintaining the subject equipment in a manner consistent with good air pollution control practices for minimizing emissions. Quarterly EERs are submitted as required containing the required information. No exceedances of NO_x or SO_2 limits were reported during the inspection period.

Source is in compliance with this condition.

1.10 Colorado Regulation No. 23, Regional Haze

1.10.1 Craig Unit 1 will close on or before December 31, 2025 (Colorado Regulation No. 23, Section IV.D.1.).

1.10.2 As provided in Condition 1.3.3, Craig Unit 1 will meet a NO_x emission limit of 0.28 lb/MMBtu over a 30-day rolling average going forward from January 1, 2017 (first compliance date January 31, 2017), until closure (Colorado Regulation No. 23, Section IV.D.2.).

1.10.3 As provided in Condition 1.3.4, Craig Unit 1 will meet an annual NO_x limit of 4,065 tons per year by December 31, 2019 on a calendar year basis beginning in 2020 (Colorado Regulation No. 23, Section IV.D.3.).

1.10.4 Compliance with the 30-day rolling average and annual NO_x limits will be monitored using the CEMS as described in Condition 19.

1.10.5 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

1.10.5.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

1.10.5.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

1.10.5.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

1.10.5.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

1.10.5.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

Tri-State has instated and operates a continuous NOx monitor at the facility consistent with the requirements of 40 CFR Part 75 and 60. Tri-State submits quarterly EERs as required. No exceedances of the NO_x emission limit of 0.28 lb/MMBtu over a 30-day rolling average were reported during the inspection period. CEMS Data and QA/QC records are maintained as required. CAM provisions are addressed as required in Semi-Annual Reports. Test reports are submitted as required. The facility monitors compliance with the annual NO_X limit using CEMS. Annual NOx emissions for the 2024 calendar year was provided and is included in the table below.

Year	Reported Annual NOx Emissions (tons/yr)	*Annual NOx Emissions Limit (tons/yr)*
2024	2,176.6	*4,065*

Source is in compliance with this condition.

1.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

The source is subject to the Acid Rain Program ("ARP"). Section III of the permit outlines the ARP requirements. Compliance with the reporting requirements is monitored through the Clean Air Markets Division (CAMD) of EPA.

Without evidence to the contrary, source is presumed to be in compliance with this condition.

1.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 1 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

Tri-State is considered to be in compliance with the requirements of 40 CFR Part 63, Subpart UUUUU with regard to Unit 1. See Condition 5.

Source is in compliance with this condition.

1.13 Compliance Assurance Monitoring (CAM)

Unit 1 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 1.1, and the SO_2 emissions in Condition 1.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G and J.

Tri-State is conducting monitoring under the CAM requirements as required. See Condition 22.

Source is in compliance with this condition.

2. Boiler B002 "Unit 2" – Coal-fired boiler, Babcock & Wilcox #NB24156, 4318 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	2.1	0.10 lb/MMBtu (NSPS Subpart D) 0.03 lb/MMBtu (CO Reg. 23, Section IV, MACT UUUUU)	Determined via Stack Testing	Baghouse O&M and Stack Testing	See Condition 2.1
SO_2	2.2	1.2 lb/MMBtu 3-hour average (CO Reg. 1, Section VI.A, NSPS D) 0.11 lb/MMBtu 30-boiler operating day rolling average (CO Reg. 23, Section IV) 0.20 lb/MMBtu, 30-boiler operating day rolling average (MACT UUUUU) 100% of flue gas treated (SIP) 0.160 lb/MMBtu 30-boiler operating day rolling average (SIP) 0.130 lb/MMBtu 90-boiler operating day rolling average (SIP) 90% reduction of SO_2 on 90-boiler operating day rolling average (SIP) No more than 72 consecutive hours of operation without SO_2 control (SIP)		CEMS Coal Sampling Calculation Recordkeeping	Continuous Daily
NOx	2.3	0.7 lb/MMBtu 3-hour average (NSPS D) 0.30 lb/MMBtu calendar year average (SIP) 0.08 lb/MMBtu 30-day rolling average (CO Reg. 23, Section IV)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.46 lb/MMBtu (see Acid Rain requirements in Section III)			
VOC & CO	2.4		See Condition 2.4	Recordkeeping and Calculation	Annually
Opacity	2.5	Not to exceed 20% except during certain operational conditions during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg. 1) Not to exceed 20% except for one 6-minute period per hour of not more than 27% and during periods of startup, shutdown, or malfunction (NSPS D, SIP) Not to exceed 20%, 6-minute average within the hour except when boiler and fans are off; not to exceed 30% during certain operational conditions (SIP) Not to exceed 30% during startup, 6-minute aggregate in any 60 consecutive minutes (SIP) Not to exceed 20% during shutdown (SIP)		COMS – May be verified by EPA Reference Method 9	Continuous, 6-Minute Intervals
Coal Requirements	2.6	Coal consumption records Coal sampling		Recordkeeping ASTM Methods	Annually Quarterly
CEMS	2.7	Monitor: Opacity, NO_x, SO_2, diluent gas, flow		See Condition 2.7	
NSPS D	2.8	See Condition 2.8			
CO SIP	2.9	See Condition 2.9			
Regional Haze	2.10	PM: 0.03 lb/MMBtu (See Condition 2.1) SO_2: 0.11 lb/MMBtu 30-day rolling average (See Condition 2.2)		CEMS	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		NO_x: 0.08 lb/MMBtu 30-day rolling average (See Condition 2.3)			
Acid Rain	2.10.2	See Section III of this Operating Permit		Certification	Quarterly and annually
MACT UUUUU (MATS)	2.12	See Condition 2.12 and 5			
CAM	2.13	See Condition 2.13			

Table 2 – Unit 2 Emissions and Requirements Summary

Unit 2 was operating during the inspection with the following emissions and operational parameters as reported by the DAHS except as noted.

Craig Station: Unit 2 Emissions and Operational Parameters (1-minute average) 10:00	
Load (gross MW)	164
Opacity of Emissions (%)	2.35(1)
CO2 (%)	7.5
Flow (scf/h)	52,421,850
NOX (lb/MMBtu)	0.037
SO2 (lb/MMBtu)	0.027
SO2 Removal (%)	96.6(2)
Stack Temp (°F)	101.4

(1) Opacity data was obtained from the monitor in the CEMS Shack at approximately the 11:00 hour.
(2) SO2 removal percentage was obtained from the scrubber control room reported as hourly data for the 11:00 hour.

Criteria pollutant emissions from Unit 2, as reported by Tri-State for calendar year 2023, are given in the table below. The permit imposes no annual mass emissions limits for Unit 2. Emissions factors shown are based on the burning of coal only. Tri-State also calculates and reports emissions from burning natural gas and fuel oil.

Tri-State G&T – Unit 2 Emissions Summary as Reported			
Pollutant	**Emissions Factor (uncontrolled)**	**2024 Emissions (tons/year)**	**Calculation Method**
PM (tons/year)	0.0120 lbs/mmBtu	81.2	2021 Stack Test
PM_{10} (tons/year)	0.0110lbs/mmBtu	74.7	2021 Stack Test
SO_2 (tons/year)	NA	302.7	CEMS
NO_x (tons/year)	NA	618.0	CEMS
VOCs (tons/year)	0.0002 lbs/mmBtu	1.8	1999 Stack Test and AP 42
CO (tons/year)	0.5 lbs/ton coal	231.6	AP 42

2.1 Particulate matter (PM) emissions must not exceed the following limits:

2.1.1 0.10 lb/MMBtu heat input, Colorado Construction Permit 10MF579 and 40 CFR Part 60, Subpart D, §60.42, as adopted in Colorado Regulation No. 6, Part A.

2.1.1.1 The Source must not cause to be discharged into the atmosphere from Unit 2 any gases that contain PM in excess of 0.10 lb/MMBtu heat input derived from fossil fuel (40 CFR Part 60, §60.42(a)(1)).

2.1.1.2 The PM standard in this condition applies at all times, except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.1.1.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

2.1.2 0.03 lb/MMBtu heat input, Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.1.2.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3 0.03 lb/MMBtu heat input, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.1.3.1 Compliance shall be established by EPA test methods, as described in Condition 2.1.5.

2.1.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.1.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.1.3.4 In addition to the stack tests required to monitor compliance as described in Condition 2.1.5, the Source must monitor compliance with the particulate matter limits in accordance with the applicable compliance assurance monitoring (CAM) plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 2.13 (Colorado Regulation No. 23, Section V.B.1.).

2.1.4 0.03 lb PM/MMBtu heat input, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

2.1.5 To demonstrate compliance with the PM emission limits in Condition 2.1, the Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16, and by conducting periodic performance testing in accordance with the requirements of Condition 17 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.1.6 Annual emissions of PM and PM_{10} for purposes of APEN reporting and payment of annual fees shall be determined using the emission factor for PM determined from the source testing required in Condition 17 and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.).:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use}\left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The fuel heat content in the above equation shall be determined by the fuel sampling required in Condition 1.6. PM_{10} emissions are calculated as 0.92 multiplied by the total PM emissions, per AP-42, 1.1-6; unless a PM_{10} emission factor was developed using source testing.

Performance testing performed July 13, 2004 averaged 0.005 lb/mmBtu. Quarterly filterable PM testing was

performed quarterly from the second quarter of 2015 through the first quarter of 2018 for purposes of qualifying as a low emitting EGU ("LEE") for MATS. MATS PM testing is now required every three years and was conducted again in the first quarter of 2024 on January 18, 2024 with passing results as approved by the Division on February 26, 2024. Quarterly performance testing and tri-annual performance testing has shown compliance with the above-mentioned limits. The baghouse is maintained in accordance with Section II, Condition 16.1. See inspector comments for Conditions 16.1 for further details. The source monitors opacity using continuous opacity monitoring. Given the low frequency of opacity exceedances, it can be assumed that the baghouse is operated in a manner consistent with good air pollution control practices. Tri-State calculates annual PM emissions and reports those emissions on annual APEN updates as required. See the table above for 2024 emissions calculations as reported by the source.

Source is in compliance with this condition.

2.2 Sulfur dioxide (SO_2) emissions must not exceed the following limits:

2.2.1 40 CFR Part 60, Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.2.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain SO_2 in excess of 1.2 lb/MMBtu heat input derived from solid fossil fuel (40 CFR Part 60, §60.43(a)(2)).

2.2.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard (40 CFR Part 60, §60.45(g)(2)(i)).

2.2.1.3 The SO_2 emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.2.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

The facility monitors compliance with the three-hour SO_2 emission limit using CEMS as required. The source reported no emissions in excess of 1.2 lbs/mmBtu heat input in any three hour period during the compliance period.

Source is in compliance with this condition.

2.2.2 1.2 lb/MMBtu, three-hour rolling average, Colorado Regulation No. 1, Section VI.A.

2.2.2.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 1.2 lb/MMBtu heat input (Colorado Regulation No. 1, Section VI.A.3.a.(ii).).

2.2.2.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.A.1.).

The facility monitors compliance with the three-hour SO_2 emission limit using CEMS as required. The source reported no emissions in excess of 1.2 lbs/mmBtu heat input in any three hour period during the compliance period.

Source is in compliance with this condition.

2.2.3 0.11 lb/MMBtu, based on a 30-day rolling average, Colorado Regulation No. 23, Section IV – Regional Haze and Colorado Regional Haze SIP

2.2.3.1 Compliance shall be monitored using the CEMS as described in Condition 2.2.5.

2.2.3.2 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.10.

2.2.3.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.2.3.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.2.3.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.2.3.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.2.3.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.2.3.8 The Source must maintain records and follow the reporting requirements as described in Condition 2.9.3, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

The facility monitors compliance with the 30-day rolling average SO_2 emission limit using CEMS. According to records provided by the facility, the unit did not exceed this limit during this inspection period.

Source is in compliance with this condition.

2.2.4 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.2.4.1 The Source must treat one hundred percent (100%) of the flue gas from Unit 2 in the flue gas desulfurization system during all operating conditions except for those time periods when an upset condition makes it impossible to treat 100% of the flue gas. However, upset conditions do not apply to the SO_2 emission limitations in this section (Condition 2.2.4) and emissions of SO_2 during any such period shall not be excluded from the determination of the Source's compliance with the SO_2 emission limitations.

2.2.4.2 The Source must not cause to be emitted into the atmosphere any gases with SO_2 in excess of the following limitations:

a. 0.160 lb/MMBtu heat input on a 30-boiler-operating-day rolling-average basis;

b. 0.130 lb/MMBtu heat input on a 90-boiler-operating-day rolling-average basis.

2.2.4.3 SO_2 controls must achieve a ninety percent (90%) reduction of SO_2 on a 90 boiler-operating-day rolling-average basis as measured from coal to stack as described in this Condition (a. through c.). Compliance with this limit shall be monitored as follows:

a. Based on the coal sampling analysis (Condition 2.6), a daily potential SO_2 emission rate for coal, expressed in lb/MMBtu, will be established. Using this daily SO_2 emission rate, for each boiler operating day in an arithmetic average of the potential SO_2 emission rates for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed) shall be calculated to establish the SO_2 rolling average basis that is referred to as E_i in the equation below. Each day's potential SO_2 emission rate for coal, before the calculation above is performed, will be provided in the reports required in Condition 19.4;

b. The rolling average basis SO_2 stack emission rate will be calculated using CEMS data collected during all operating hours in a boiler operating day. To establish the SO_2 rolling average basis, all hourly emission rates, as derived from the CEMS data, and expressed in lb/MMBtu, for the last 90 successive boiler operating days (including the boiler operating day for which the calculation is being performed), will be used to calculate that day's SO_2 rolling average basis that is referred to as E_0 in the equation below. Each day's SO_2 stack emission rate for the hours that the boiler was operating, before the calculation above is performed, will be reported under Condition 19.4;

c. The 90 day rolling average basis percent SO_2 reduction, referred to herein as %R, shall be calculated for each boiler operating day as follows:

$$\%R = 100 * (1.0 - \frac{E_0}{E_i})$$

2.2.4.4 Regardless of the Source's compliance with (and without relieving the Source of the obligation to comply with) the emission limitations and other requirements set forth in Condition 2.2.4, in no event shall the Source operate any boiler for more than 72 consecutive hours at a unit without an SO_2 control system achieving some reduction of SO_2 emissions at that unit. Following shutdown pursuant to this Condition, the Source shall only restart the boiler on a unit when the SO_2 control equipment is operating normally.

All exhaust gas from Unit 2 is treated by the wet flue gas desulfurization ("WFGD") unit to remove SO_2 and acid gasses prior to discharge into the atmosphere. The source reported that Unit 2 operated with no emissions in excess of any SO_2 limit for the compliance period, which indicates good air pollution control.

The facility monitors compliance with the 30-day SO_2 emission limit using CEMS. According to records provided by Tri-State, Unit 2 did not exceed this limit during this inspection period.

The facility monitors compliance with the 90-day SO_2 emission limit using CEMS. According to records provided by the facility, the unit did not exceed this limit during this inspection period.

The facility monitors compliance with the Unit 2 SO_2 reduction requirements using outlet CEMS and coal analysis. According to records provided by the facility, the unit did not fail to meet 90% reduction requirement in any 90 day rolling average during this inspection period. During the inspection, the Unit 2 SO_2 removal rate was 96.6% as measured by the CEMS.

According to facility records, in no cases did the unit operate without achieving any SO_2 reduction during this inspection period.

Source is in compliance with this condition.

2.2.5 Compliance calculations for SO_2 requirements in Condition 2.2 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

2.2.5.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

2.2.6 Annual emissions of SO_2 for APEN reporting and fee purposes shall be determined from the CEMS as required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

Tri-State monitors emissions of SO_2 using a CEMS as required and calculates SO_2 emissions consistent with the specified methodologies above. Tri-State calculates annual SO_2 emissions and reports those emissions on annual APEN updates as required. See the table above for 2024 emissions calculations as reported by the source. Tri-State conducts operation and maintenance of the scrubber consistent with the requirements of Permit Condition 16.

Source is in compliance with this condition.

2.3 Nitrogen oxides (NO_x) emissions must not exceed the following limits:

2.3.1 40 CFR Part 60, Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators, as adopted by reference in Colorado Regulation No. 6, Part A

2.3.1.1 The Source shall not cause to be discharged into the atmosphere from any affected facility any gases that contain NO_x, expressed as NO_2 in excess of 0.7 lb/MMBtu heat input derived from solid fossil fuel (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse) (40 CFR Part 60, §60.44(a)(3)).

2.3.1.2 Excess emissions are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the

applicable standards (40 CFR Part 60, §60.45(g)(3)(i)).

2.3.1.3 The NO_x emission standards in this condition apply at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.8(c)).

2.3.1.4 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

The facility monitors compliance with the rolling three-hour NO_x emission limit using CEMS as required. According to records provided by Tri-State, Unit 2 NO_X emissions did not exceed 0.7 lbs/mmBtu on a 3-hour rolling basis during the inspection period.

Source is in compliance with this condition.

2.3.2 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.3.2.1 The Source must not cause to be emitted into the atmosphere any gases with NO_x in excess of 0.30 lb/MMBtu heat input on a calendar year annual average basis. Upset conditions do not apply to this limit and emissions of NO_x during any such period shall not be excluded from the determination of the Source's compliance with the NO_x emission limit. Compliance shall be determined on a unit-specific basis using data from NO_x CEMS that the Source is required to maintain, calibrate, and operate. Specific requirements related to the CEMS are outlined in Condition 2.7.

2.3.2.2 The Source must operate state-of-the-art low-NO_x burners utilizing two stage combustion with supplemental overfire air.

The facility monitors compliance with the annual NO_X limit using CEMS as required. According to facility records, there were no violations of the annual 0.30 lbs/MMBtu NO_X limit during the inspection period. Reported emissions for data year 2024 were 0.057 lb/MMBtu. The boiler is equipped with low-NOx burners utilizing two stage combustion with supplemental over fire air as required.

Source is in compliance with this condition.

2.3.3 0.08 lb/MMBtu, based on a 30-day rolling average, Colorado Regulation No. 23, Section IV – Regional Haze, as provided for in Condition 2.9.3

2.3.3.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

2.3.3.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 2.3.3.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.4 In determining compliance with the NO_x regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

2.3.3.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 2.3.3.2. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

2.3.3.6 Compliance shall be monitored using the CEMS as described in Condition 2.3.4.

2.3.3.7 The Source must perform the Regional Haze recordkeeping and reporting requirements associated with this limit as described in Condition 2.102.9.3.

The facility monitors compliance with the 30-day rolling average NO_x emission limit using CEMS as required. According to records provided by Tri-State, Unit 1 NO_X emissions did not exceed 0.08 lb/MMBtu calculated on a 30-day rolling average during the inspection period.

Source is in compliance with this condition.

2.3.4 Compliance calculations for NO_x requirements in Condition 2.3 shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.3.4.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

2.3.4.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

2.3.4.3 The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

Tri-State monitors emissions of NO_X using a CEMS as required and calculates NO_x emissions consistent with the specified methodologies above.

Source is in compliance with this condition.

2.3.5 Annual emissions of NO_x for APEN reporting and fee purposes shall be determined from the CEMS required by Condition 2.7 (Colorado Regulation No. 3, Part C, Section V.C.5.).

Tri-State calculates annual NO_x emissions and reports those emissions on annual APEN updates as required. See the table above for 2024 emissions calculations as reported by the source.

Source is in compliance with this condition.

2.4 Volatile Organic Compounds (VOC) and Carbon Monoxide (CO)

2.4.1 Annual emissions for the purposes of APEN reporting and annual fees shall be calculated using the Division approved emission factors (AP-42, Section 1.1, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.) and the annual fuel usage, as required by Condition 2.6 in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{ton_{CO\ or\ VOC}}{yr} = Emission\ factor\ \left[\frac{lb}{ton}\right] * \ annual\ fuel\ usage\ \left[\frac{ton}{yr}\right] * \frac{1\ ton}{2000\ lb}$$

Tri-State reports annual emissions from Unit 2 on APENs as required using the appropriate emissions factors listed in the permit and from 1999 stack test data. The permit imposes no annual mass emissions limits for VOC or CO. Annual SO_2 and NO_x emissions are measured using the CEMS as required. The permit imposes no annual NO_X or SO_2 mass emissions limits. See the table above §II, Condition 2.1 for annual emissions from data year 2024 as reported by Tri-State.

Source is in compliance with this condition.

2.5 Opacity

2.5.1 Colorado Regulation No. 1

2.5.1.1 Except as provided in Condition 2.5.1.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

2.5.1.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

Unit 2 is equipped with COMS to monitor opacity. Opacity of emissions in excess of any standard is reported on quarterly EERs as required. The source did not report any exceedances of opacity standards during the inspection period. The source was operating during the inspection and no visible emissions were observed. During the inspection the opacity as read by the COMS was 2.35%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

2.5.2 40 CFR Part 60, Subpart D

2.5.2.1 The Source shall not discharge into the atmosphere any gases that exhibit greater than 20 percent (%) opacity except for one six-minute period per hour of not more than 27 percent opacity (40 CFR Part 60, §60.42(a)(2)).

2.5.2.2 The opacity standards set forth in 40 CFR Part 60 shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard (40 CFR Part 60, §60.11(c)).

2.5.2.3 Additional requirements associated with 40 CFR Part 60, Subpart D are described in Condition 2.8.

Unit 2 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. The source was operating during the inspection and no visible emissions were reported. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 2.35%. The source did not report any exceedances of opacity limits during the inspection period.

Source is in compliance with this condition.

2.5.3 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.5.3.1 Opacity must not be in excess of 20 percent (%), as averaged over each separate 6-minute period within an hour, beginning each hour on the hour. This limit shall apply at all times when air pollutants are being discharged into the atmosphere, but does not apply when the boiler and all fans that move flue gas in the unit are off. Under this limit, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, the Source must not cause or allow the emission of air pollutants in excess of 30 percent opacity for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes.

a. The Source must not cause or allow the emission air pollutants in excess of 30 percent opacity during any startup, regardless of cause or reason, for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes. A startup is never an upset condition; however, an upset condition can occur after initiation of a startup, in which case only excess emissions caused by such upset condition may be excused.

b. The Source must not cause or allow the emission of air pollutants in excess of 20 percent opacity during any shutdown, unless excused by an upset condition.

2.5.3.2 Opacity must not be greater than 20 percent except for one six-minute period per hour of not more than 27 percent opacity, as averaged over each separate 6-miunte period within an hour, beginning each hour on the hour. Emissions during startup, shutdown, and malfunction are excused under this opacity limit; however, cleaning of new fire boxes, soot blowing, and any process modification or adjustment or occasional cleaning of control equipment are not excused.

2.5.3.3 An opacity reading in excess of the limitations in Condition 2.5.3.1 may be excused by an upset condition, and an opacity reading in excess of the limitations in Condition 2.5.3.2 may be excused by a malfunction, if the Source demonstrates such reading was the result of an upset condition or malfunction. If the Source seeks to excuse any opacity reading in excess of the above limitations, the Source must notify the Division as soon as possible by telephone, but no later than two hours after the start of the next business day. In addition, for purposes of this SIP component, any claim of excuse must be made in writing in the Source's next quarterly report following such condition, and must describe:

a. The date and time telephone notification was given to the Division, including the person to whom notification was given either directly or through a voice mailbox,

b. The cause of the condition,

c. All actions the Source took to correct the condition, and

d. All actions the Source will take to prevent the condition from recurring.

2.5.3.4 The Source must file quarterly excess emission reports (EERs) that set forth all 6-minute average opacity readings in excess of 20 percent in chronological order. The Source must indicate in the EERs the specific times in which the fans that move flue gas are on and off. At the Source's election, periods of "process off" and "process on" may be identified in a separate document included with, or attached to, the EER. Sufficient explanation to support any claim of upset condition or malfunction must be provided at the time the EER is filed.

Unit 2 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. The source did not report any exceedances of opacity standards during the inspection period. The source was operating during the inspection and no visible emissions were observed. During the inspection, the unit was in normal operation, and the opacity as read by the COMS was 2.35%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

2.5.4 Compliance with the opacity emissions limitations in Condition 2.5 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4 (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.5.4.1 The requirements for the COMS system are outlined in Condition 19.

2.5.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

Unit 2 is equipped with COMS as required. The source did not monitor compliance with opacity requirements with EPA Method 9 during the inspection period. Opacity in excess of any standard is reported on quarterly EERs as required. The source did not report any exceedances of opacity standards during the inspection period. The source was operating during the inspection and no visible emissions were observed. During the inspection, the unit was operating, and the opacity as read by the COMS was 2.35%. Method 9 has not been utilized for compliance with opacity requirements. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

2.5.5 Partial streamlining of opacity limits into State Implementation Plan opacity limits – The regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions

2.5.1 and 2.5.2 respectively) shall be streamlined into the State Implementation Plan opacity limits (Condition 2.5.3), except as follows:

2.5.5.1 *When the boiler and all fans that move flue gas in the unit are off.* Anytime the boiler and all fans that move flue gas in the unit are off, the regulatory opacity limits described in Colorado Regulation No. 1 and NSPS D (Conditions 2.5.1 and 2.5.2 respectively) shall continue to apply and shall not be streamlined into the State Implementation Plan opacity limits.

2.5.5.2 Opacity readings based on a 6-minute period that is not a "separate 6-minute period within an hour, beginning each hour on the hour." The regulatory opacity limits described in Colorado Regulation No. 1, Section II.A.1 (Condition 2.5.1.1) and 40 CFR Part 60, §60.42(a)(2) (Condition 2.5.2.1) apply to any 6-minute period. In contrast, the corresponding SIP opacity limit are "averaged over each separate 6-minute period within an hour, beginning each hour on the hour." The Source must comply with the regulatory opacity limits at all times, without regard to when the 6-minute period begins. This means that:

a. The regulatory opacity limits must not be streamlined into the SIP opacity limits in any case in which there is an opacity reading that, due to the timing of the 6-minute period, shows a violation of a regulatory limit but compliance with the SIP opacity limits.

b. The regulatory opacity limits shall be streamlined into the SIP opacity limits to the extent the same emissions event violated the SIP opacity limits as well as the regulatory limits.

Unit 2 is equipped with COMS to monitor opacity. Opacity of emissions in excess of any standard is reported on quarterly EERs as required. The source did not report any exceedances of opacity standards during the inspection period. The source was operating during the inspection and no visible emissions were observed. During the inspection, the unit was operating and the opacity as read by the COMS was 2.35%. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

2.6 Coal Requirements

2.6.1 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years (Colorado Regulation No. 3, Part C, Section V.C.5.).

2.6.2 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20 (Colorado Regulation No. 3, Part C, Section V.C.5.).

Annual fuel consumption records are maintained as required. Actual fuel consumption by Unit 1 for Calendar year 2024 are shown in the table below. Belt scale calibration reports for 2024 were reviewed. Belt scales are calibrated at least annually as required. Coal samples are taken and analyzed daily. See inspector comments for Condition 20 for further details.

Tri-State G&T – Craig Station Unit 2 Fuel Use

Year	Coal Consumed (tons)	Fuel Oil Consumed (gallons)	Natural Gas Consumed (Mcf)
2024	926,371	29,484	66,030
Limit:	*NA*	*NA*	*NA*

Source is in compliance with this condition.

2.7 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, 40 CFR Part 75, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

2.7.1 For this emission unit, the Source operates a mercury (Hg) CEMS to monitor compliance with the Hg requirements of 40 CFR Part 63, Subpart UUUUU (MATS, as described in Condition 5). The Hg CEMS must be operated in accordance with the requirements of 40 CFR Part 63, Subpart UUUUU, Appendix A. (40 CFR Part 63, Subpart UUUUU, §63.10010(g)).

Unit 2 is equipped with continuous Opacity, SO_2, NO_x, CO_2, Hg and Flow monitors as required. All CEMS equipment were reported to be operating appropriately during the inspection. See inspector comments for Condition 19 for further details.

Source is in compliance with this condition.

2.8 40 CFR Part 60, Subpart D

2.8.1 For performance evaluations under §60.13(c) and calibration checks under §60.13(d), the procedures in §60.45(c)(1) through (5) must be used (40 CFR Part 60, §60.45(c)).

In conducting the performance tests required in 40 CFR part 60, §60.8, and subsequent performance tests as required by the EPA Administrator, the Source must use as reference methods and procedures the test methods in 40 CFR Part 60, Appendix A or other methods and procedures as specified in §60.46, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in §60.46(d) (40 CFR Part 60, §60.46(a)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart D.

2.8.2 The Source shall determine compliance with the PM, SO_2, or NO_x standards in §60.42, §60.43, and §60.44 as described in 40 CFR Part 60, §60.46(b)(1) through (5) (40 CFR Part 60, §60.46(b)). Note that the requirements associated with CEMS are described in Condition 19.

2.8.3 **[Excess emissions reports]** Excess emission and monitoring system performance reports shall be submitted to the Administrator semiannually for each six-month period in the calendar year. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period. Each excess emission and MSP report shall include the information required in §60.7(c). Periods of excess emissions and monitoring systems downtime that shall be reported are defined as follows (40 CFR Part 60, §60.45(g)):

2.8.3.1 *Opacity* – Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six minute-average per hour of up to 27 percent opacity need not be reported (40 CFR Part 60, §60.45(g)(1)).

2.8.3.2 *Sulfur dioxide* – For affected facilities electing not to comply with §60.43(d) (Condition 2.2.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of SO_2 as measured by a CEMS exceed the applicable standard in §60.43 (40 CFR Part 60, §60.45(g)(2)(i)); or if the Source elects to comply with §60.43(d) they must follow the provisions in §60.45(g)(2)(ii).

2.8.3.3 *Nitrogen oxides* – For affected facilities electing not to comply with §60.44(e) (Condition 2.3.1), any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards in §60.44 (40 CFR Part 60, §60.45(g)(3)(i)); or if the Source elects to comply with §60.44(e) they must follow the provisions in §60.45(g)(3)(ii).

2.8.4 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

Unit 2 is equipped with continuous Opacity, SO_2 and NO_x monitors that conform to the requirement for 40 CFR Part 60 as required. Excess Emissions Reports are submitted as required. Tri-State did not report any exceedances of opacity limits, nor SO_2 or NO_x limits during the inspection period. Tri-State complies with the requirements of 40 CFR Part 60, Subpart A as required. See Conditions 18 and 19.

Source is in compliance with this condition.

2.9 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)

2.9.1 At all times, including periods of startup, shutdown, and malfunction, the Source shall maintain and operate Unit 2 in a manner consistent with good air pollution control practices for minimizing emissions.

2.9.2 The Source has the burden of proof to demonstrate the application of any exception to any applicable emission limit, and must provide sufficient demonstration of the application of any exception in their contemporaneous excess emission reports (EERs).

2.9.3 Within thirty (30) days of a request by the Division, the Source must provide a report to the Division regarding the immediately preceding quarter that contains all of the following information with regard to the requirements in the 2001 SIP component:

2.9.3.1 Specifically, each report shall include:

a. All elements of the opacity, SO_2, NO_x quarterly excess emission and monitoring report;

b. The required reports for SO_2 emissions (including emissions during all excluded periods as well as SO_2 content calculated from coal for each day, the SO_2 stack emissions for each day, and each day's SO_2 percent removal rate), coal sulfur analyses, pressure drop and flow data relating to the mist eliminators, and quarterly reports required under 40 CFR Part 60 containing CEMS quality assurance information;

c. The required year-to-date quarterly reports for NO_x emissions.

2.9.3.2 The Source's requirement to provide the requested reports in this condition is in addition to any other notification or report required by the 2001 SIP component,

unless such notification or report is required on a quarterly basis. Furthermore, nothing in the 2001 SIP component shall be interpreted to either excuse or diminish the Source's obligation to provide any other reports, notices or other documents to the public, or local, state, or federal agencies.

No evidence was observed or discovered during the inspection to indicate that Tri-State is not operating and maintaining the subject equipment tin a manner consistent with good air pollution control practices for minimizing emissions. Quarterly EERs are submitted as required containing the required information. No exceedances of NO_x or SO_2 limits were reported during the inspection period.

Source is in compliance with this condition.

2.10 Colorado Regulation No. 23, Regional Haze

2.10.1 Craig Unit 2 will close no later than September 30, 2028 (Colorado Regulation No. 23, Section IV.F.1.e.).

2.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

2.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

2.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

2.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

2.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

2.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

Tri-State submits quarterly EERs as required. No exceedances of the NO_x emission limit of 0.28 lb/MMBtu over a 30-day rolling average were reported during the inspection period. CEMS Data and QA/QC

records are maintained as required. CAM provisions are addressed as required in Semi-Annual Reports. Test reports are submitted as required.

Source is in compliance with this condition.

2.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

The source is subject to the Acid Rain Program ("ARP"). Section III of the permit outlines the ARP requirements. Compliance with the reporting requirements is monitored through the Clean Air Markets Division (CAMD) of EPA.

Without evidence to the contrary, source is presumed to be in compliance with this condition.

2.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 2 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

Tri-State is in compliance with the requirements of 40 CFR Part 63, Subpart UUUUU with regard to Unit 2. See Condition 5.

Source is in compliance with this condition.

2.13 Compliance Assurance Monitoring (CAM)

Unit 2 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 2.1, the SO_2 limitations in Condition 2.2, and the NO_x limitations in Condition 2.3. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22, and Appendices G, J, And L.

Tri-State is conducting monitoring under the CAM requirements as required. See Condition 22.

Source is in compliance with this condition.

3. Boiler B003 "Unit 3" – Coal-fired boiler, Babcock & Wilcox #NB24602, 4600 MMBtu/hr

Pulverized-coal dry-bottom boiler: natural gas, propane, or fuel oil used at startup and shutdown, and for flame stabilization

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Particulate Matter (PM)	3.1	443 tons/year, 12-month rolling total 0.03 lb/MMBtu (Filterable, MATS) 0.013 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)	Stack Performance Testing	Baghouse O&M Stack Performance Testing	Continuous See Condition 3.1
PM_{10}		403 tons/year, 12-month rolling total 0.012 lb/MMBtu (Filterable, BACT and CO Reg 23) 0.018 lb/MMBtu (Filterable and condensable, BACT)			
SO_2	3.2	2,125 tons/year 0.20 lb/MMBtu, daily average, except one daily average per month which may exceed 0.20 lb/MMBtu (BACT) 80% reduction of potential emissions, 30-day average (BACT) 1.20 lb/MMBtu, 90% reduction of potential emissions; 70% reduction of potential emissions when emissions are less than 0.60 lb/MMBtu, 30-day rolling average (NSPS Da)	CEMS	CEMS Stack Performance Testing Coal Sampling, Calculation, Recordkeeping	Continuous See Condition 3.2 Daily

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		0.4 lb/MMBtu, 3-hour rolling average (CO Reg 1) 0.15 lb/MMBtu, 30-day rolling average (CO Reg 23) 0.20 lb/MMBtu, 30-day rolling average (MATS)			
NOx	3.3	6,752 tons/year 0.50 lb/MMBtu, 30-boiler operating day rolling average (NSPS Da & BACT) 0.28 lb/MMBtu, 30-boiler operating day rolling average (CO Reg 23)	CEMS	CEMS	Continuous
CO	3.4	4,332 tons/year 1.25 lb/MMBtu, 8-hour rolling average (BACT)	CEMS	CEMS	Continuous
VOC	3.5	58 tons/year	0.003 lb/MMBtu, or AP-42, EPRI, stack test data	Recordkeeping and Calculation	Monthly
Lead (Pb)		0.054 tons/year	2.82 lb/TBtu, or AP-42, EPRI, stack test data		
Sulfuric Acid Mist (SAM)		0.10 tons/year	See Condition 3.5		
Fluorides		4.47 tons/year	232.74 lb/TBtu, or AP-42, EPRI, stack test data		
Opacity	3.6	Not to exceed 10% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT) During startup and shutdown, not to exceed 20% averaged over 6-minute periods within an hour, except for one 6-minute period of not more than 27% opacity (BACT)		COMS – May be verified by EPA Reference Method 9	Continuous

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
		Not to exceed 20% except during certain operational condition during which opacity not to exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (CO Reg 1) Not to exceed 20% (CO Reg 6 – State-only)			
Coal Requirements	3.7	1,897,344 tons/year Coal sampling		Recordkeeping ASTM Methods	Monthly Quarterly
CEMS	3.8	Monitor: Opacity, NO_x, SO_2, CO, CO_2, diluent gas, flow		See Condition 3.8	
NSPS Da	3.9	See Condition 3.9			
Regional Haze	3.10	See Condition 3.10			
Acid Rain	3.10.2	See Section III of this Operating Permit		Certification	Quarterly and Annually
MACT UUUUU (MATS)	3.12	See Conditions 3.12 and 5			
CAM	3.13	See Condition 3.13			

Table 3 – Unit 3 Emissions and Requirements Summary

Unit 3 was not operating during the inspection with the following emissions and operational parameters.

Tri-State G&T Craig Station Unit 3 Emissions and Operational Parameters (1-minute average)	
Load (gross MW)	0
Opacity of Emissions (%)	0
CO2 (%)	0
Flow (scf/h)	0
NOx (lb/MMBtu)	0
SO2 (lb/MMBtu)	0
SO2 Removal (%)	NA
CO lb/MMBtu	0
Stack Temp (°F)	NA

3.1 Particulate matter (PM) and particulate matter less than or equal to 10 microns (PM_{10}) emissions must not exceed the following limits:

3.1.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for PM and PM_{10}. The Division and the EPA have determined that the following limits meet the BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.1.1.1 [Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu

a. Compliance with the filterable PM limit will be monitored by stack testing as required in Condition 3.1.4. Compliance with the filterable PM_{10} limit will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.2 [Total Filterable and Condensable] 0.018 lb PM/MMBtu heat input, 0.018 lb PM_{10}/MMBtu

a. Compliance with these limits will be monitored by the stack testing as required in Condition 3.1.4.

3.1.1.3 [Total Filterable and Condensable] 443 tons PM/year, 403 tons PM_{10}/year

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Compliance with these limits will be monitored per the requirements in Condition 3.1.4.

3.1.2 [Filterable only] 0.013 lb PM/MMBtu, 0.012 lb PM_{10}/MMBtu, Colorado Regulation No. 23, Section IV.B.

3.1.2.1 Compliance with this limit will be monitored by the stack testing as required in Condition 3.1.4 and by demonstrating compliance with the CAM plan developed and approved in accordance with 40 CFR Part 64, as described in Condition 3.13 (Colorado Regulation No. 23, Section V.B.1.).

3.1.2.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.1.2.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.B.3.).

3.1.3 0.03 lb PM/MMBtu, 40 CFR Part 63, Subpart UUUUU, as provided in Condition 5.1.2 (Table 2 of Subpart UUUUU).

3.1.4 To demonstrate compliance with PM and PM_{10} emission limits in Condition 3.1, the Source must:

3.1.4.1 For filterable $PM_{10,}$ and total filterable and condensable emission limitations compliance shall be monitored by conducting performance tests as required by Condition 17.

3.1.4.2 The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.1.4.3 For annual filterable and condensable emission limitations, compliance shall be monitored by calculating emissions using the total PM and PM_{10} emission factors from the most recent performance test, and the monthly quantity of heat input to the boiler in the following equation:

$$\frac{tons\ PM}{year} = emission\ factor\ \left[\frac{lb}{MMBtu}\right] * \text{fuel use} * \left[\frac{\text{tons}}{\text{year}}\right] * fuel\ heat\ content\ \left[\frac{MMBtu}{ton}\right] * \frac{\text{ton}}{2000\ lb}$$

The monthly heat input to the boiler shall be determined using the monthly coal consumption and the average heat content of the coal, as determined by the coal sampling as required in Condition 3.7.3. Monthly emissions shall be used in a rolling twelve-month total to monitor compliance with the annual limitation. Each month a new twelve-month total shall be calculated using the previous twelve-months' data.

Tri-State is required to conduct stack testing bi-annually for compliance with BACT PM limits. The most recent testing for PM was conducted on June 5, 2024 with passing results. The Division reviewed and approved this testing on August 21, 2024. Tri-State is currently required to conduct testing for compliance with the MATS low emissions emitter (LEE) limit for PM every three years. The June 5, 2024 testing indicated compliance with the MATS LEE PM requirements. Tri-State is implementing the measures in the CAM Plan as required. The baghouse is operated and maintained as required. Annual emissions of PM and PM10 are calculated using the specified calculation methodology on a rolling 12-month total as required. Records of annual PM and PM 10 emissions were provided and are summarized in the table below. A review of records provided indicates that Tri-State has not exceeded the annual emissions limits.

Tri-State G&T Craig Station Unit 3 Annual Coal PM and PM10 Emissions		
Period	**Reported Annual Emissions (tons/yr)**	
	PM	**PM10**
3/2023-2/2024	94.6	73.6
1/2024-12/2024	66.4	47.0
2/2024-1/2025	61.8	42.8
Limits:	*443*	*403*

Source is in compliance with this condition.

3.2 Sulfur dioxide (SO_2) emissions must not exceed the following limits:

3.2.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for SO_2. The Division and the EPA have determined that the following limits meet the BACT requirements and that the following BACT limits apply at all times, as specified. Note that the annual limits are not considered BACT.

3.2.1.1 0.20 lb/MMBtu heat input, as averaged over any calendar day, to be exceeded no more than once during any calendar month.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with this emission limitation is determined by calculating the arithmetic average emissions for any calendar day from the individual hourly values, for each Unit Operating Hour, defined as "a clock hour during which a unit combusts any fuel, either for part of the hour or for the entire hour," by 40 CFR Part 72, §72.2.

3.2.1.2 80% reduction of the potential combustion concentration of SO_2, as determined on a 30-day rolling average basis.

a. This limit applies during periods of startup and shutdown (EPA PSD Permit).

b. Compliance with the percentage reduction requirement is based on the average emission rate for 30 successive boiler operating days. A separate performance test

is completed at the end of each boiler operating day, and a new 30-boiler operating day rolling average emission rate and a new percent reduction for SO_2 are calculated to show compliance with the standards (40 CFR Part 60, §60.48Da(b)).

c. Compliance is determined by calculating the arithmetic average of all valid hourly emission rates for SO_2 for the 30 successive boiler operating days. Compliance with the percentage reduction requirement for SO_2 is determined based on the average inlet and average outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.1.3 2,125 tons of SO_2 per year

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

3.2.1.4 Compliance with these limits shall be monitored using the CEMS as required in Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

Compliance with the daily average limit and reduction limit is monitored using inlet and outlet SO_2 – diluent CEMS. Diluent capping is applied when applicable. The reduction efficiency is determined by comparing inlet and outlet SO_2 emissions rates. The source reported achieving 80% SO_2 reduction on a 30 day rolling average at all times during the inspection period. The source did not report any daily SO2 average emissions periods in excess of the 0.20 lb/MMBtu daily average limit during the inspection period.

The SO_2 outlet CEMS is used to calculated annual emissions of SO_2 on a rolling 12-month total as required. Annual SO_2 emissions records were provided and are summarized in the table below. A review of records provided indicates that Tri-State has not exceeded the annual SO_2 emissions limit.

Tri-State G&T Craig Station Unit 3 Annual SO_2 Emissions	
Period	**Reported Annual Emissions (tons/yr)**
	SO_2
3/2022-2/2024	1,165.1
1/2024-12/2024	666.1
2/2024- 1/2025	603.0
Limits:	*2,125*

Source is in compliance with this condition.

3.2.2 40 CFR Part 60, Subpart Da, §60.43Da

3.2.2.1 When combusting solid fuel, as applicable, the Source shall not emit into the atmosphere any gases which contain SO_2 emissions in excess of either (40 CFR Part 60, §60.43Da(a):

a. 520 ng/J (**1.20 lb/MMBtu**) heat input and 10 percent of the potential combustion concentration (**90 percent reduction**) (40 CFR Part 60, §60.43Da(a)(1));

b. 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(2));

c. 180 ng/J (1.4 lb/MWh) gross energy output (40 CFR Part 60, §60.43Da(a)(3)); or

d. 65 ng/J (0.15 lb/MMBtu) heat input (40 CFR Part 60, §60.43Da(a)(4)).

3.2.2.2 This SO_2 emission limit applies at all times except during periods of startup,

shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.2.2.3 Compliance with the applicable SO_2 emission limit and percentage reduction requirements under 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for SO_2 and a new percent reduction for SO_2 are calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.2.2.4 Compliance with the applicable 30-boiler operating day rolling average for SO_2 emission limits is determined by calculating the arithmetic average of all hourly emission rates for SO_2 for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.2.2.5 Compliance with the applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days (40 CFR Part 60, §60.48Da(e)).

3.2.2.6 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.2.2.7), compliance with the SO_2 emission requirements in §60.43Da (Condition 3.2.2.1) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part 60, §60.48Da(h)).

3.2.2.7 The Source shall calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring SO_2 emissions, as follows: (40 CFR Part 60, §60.49Da(b)).

a. Sulfur dioxide emissions are monitored at both the inlet and outlet of the SO_2 control device (40 CFR Part 60, §60.49Da(b)(1)).

b. For a facility that qualifies under the numerical limit provisions of §60.43Da, SO_2 emissions are only monitored as discharged to the atmosphere (40 CFR Part 60, §60.49Da(b)(2)).

c. An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 of Appendix A to 40 CFR Part 60 may be used to determine potential SO_2 emissions in place of a continuous SO_2 emission monitor at the inlet to the SO_2 control device as required under §60.49Da(b)(1) (Condition 3.2.2.7.a.) (40 CFR Part 60, §60.49Da(b)(3)).

d. If the Source has installed and certified an SO_2 CEMS according to the requirements of §75.20(c)(1) of 40 CFR Part 75 and Appendix A of Part 75, and is continuing to meet the ongoing QA requirements of 40 CFR Part 70, §75.21 and Appendix B of Part 75, that CEMS may be used to meet the requirements of §60.49Da(b) (Condition 3.2.2.7), provided that the following conditions are met (40 CFR Part 60, §60.49Da(b)(4)):

(i) A CO_2 or O_2 (continuous monitoring system) CMS is installed, calibrated, maintained and operated at the same location, according to §60.49Da(d) (Condition 3.2.2.7.e.) (40 CFR Part 60, §60.49Da(b)(4)(i)); and

(ii) For Sources subject to an SO_2 emission limit in lb/MMBtu under §60.43Da (40 CFR Part 60, §60.49Da(b)(4)(ii)):

a) When relative accuracy testing is conducted, SO_2 concentration data and CO_2 (or O_2) data are collected simultaneously (40 CFR Part 60, §60.49Da(b)(4)(ii)(A)); and

b) In addition to meeting the applicable SO_2 and CO_2 (or O_2) relative accuracy specifications in Figure 2 of 40 CFR Part 75, Appendix B, the relative accuracy standard in section 13.2 of Performance Specification 2 in Appendix B to Part 75 is met when the relative accuracy is calculated on a lb/MMBtu basis (40 CFR Part 60, §60.49Da(b)(4)(ii)(B)); and

(iii) The reporting requirements of §60.51Da are met. The SO_2 and, if required, CO_2 (or O_2) data reported to meet the requirements of §60.51Da shall not include substitute data values derived from the missing data procedures of 40 CFR part 75, nor shall the SO_2 data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 75, §60.49Da(b)(4)(iii)).

e. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where SO_2 emissions are monitored. For affected facilities subject to a lb/MMBtu SO_2 emission limit under §60.43Da (Condition 3.2.2.1), if the Source has installed and certified a CO_2 or O_2 monitoring system according to 40 CFR Part 75, §75.20(c) and Appendix A to Part 75 and the monitoring system continues to meet the applicable QA provisions of 40 CFR Part 75, §75.21 and Appendix B of Part 75, that CEMS may be used together with the Part 75 SO_2 concentration monitoring system described in §60.49Da(b) (Condition 3.2.2.7), to determine the SO_2 emission rate in lb/MMBtu. SO_2 data used to meet the requirements of §60.51Da (Condition 3.9.2) shall not include substitute data values derived from the missing data procedures in 40 CFR Part 75, Subpart D, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(d)).

f. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

g. Additional CEMS requirements are described in Condition 3.8.

3.2.2.8 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for SO_2. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.2.2.9 The Source shall demonstrate compliance with the SO_2 standards in 40 CFR Part 60, §60.43Da (Condition 3.2.2.1) as described in §60.50Da(c)(1) through (5) (40 CFR Part 60, §60.50Da(c)).

3.2.2.10 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.2.3 0.4 lb/MMBtu heat input, 3-hour rolling average, Colorado Regulation No. 1, Section VI.B.4.

3.2.3.1 The Source shall not cause to be discharged into the atmosphere any emissions of gases in excess of 0.4 lb SO_2/MMBtu heat input (Colorado Regulation No. 1, Section VI.B.4.a.(iii)).

3.2.3.2 The averaging time for this emission limitation is based on a three-hour rolling average (Colorado Regulation No. 1, Section VI.B.2.).

3.2.4 0.15 lb/MMBtu, based on a 30-day rolling average, Colorado Regulation No. 23, Section IV.B.

3.2.4.1 Compliance with this limit will be monitored by the CEMS as required in Condition 3.8 (Colorado Regulation No. 23, Section V.A.1.).

3.2.4.2 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as applicable (Colorado Regulation No. 23, Section V.C. & D.).

3.2.4.3 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.2.4.4 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.5 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.2.4.4, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the SO_2 emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.6 In determining compliance with the SO_2 regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.2.4.7 For any hour in which fuel is combusted, the Source shall calculate hourly average SO_2 concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.2.4.4. These hourly average shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.2.5 Compliance calculations for SO_2 requirements in Condition 3.2, with the exception of the annual emission limit in Condition 3.2.1.3, shall be performed using one-hour average emission rates as determined by the CEMS as required in Condition 3.8. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average SO_2 concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.2.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the three-hour rolling average calculation.

3.2.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

a. With respect to the requirements of 40 CFR Part 63, Subpart UUUUU, reported 30-day rolling averages shall follow the regulation as published in the most current version of the rule in the Federal Register.

3.2.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.2.1.3, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr SO_2 emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.2.6.1 Hourly mass SO_2 emissions (in lbs/hr) shall be determined by taking the hourly 40 CFR Part 75 SO_2 ppm value (which includes replaced or bias-adjusted data, as applicable), multiplying it by the hourly 40 CFR Part 75 stack flow rate (which includes replaced or bias adjusted data, as applicable) and the multiplying it by the applicable conversion factor. The resulting SO_2 lb/hr value (which is calculated using the appropriate equation in Appendix F of 40 CFR Part 75) is then multiplied by the unit operating time for that hour to produce a SO_2 lbs value. Hourly SO_2 mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly SO_2 emissions (in tons).

3.2.7 The Source must perform the appropriate operation and maintenance of the scrubber in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

Compliance with the SO_2 limits and SO_2 reduction limits are monitored using inlet and outlet SO_2 – diluent CEMS. The SO_2 CEMS are operated and maintained consistent with the requirements of 40 CFR Part 60 and 40 CFR Part 75. The reduction efficiency is determined by comparing inlet and outlet SO_2 emissions rates. The reduction efficiency is determined by comparing inlet and outlet SO_2 emissions rates. The source reported achieving 70% SO_2 reduction on a 30 day rolling average at all times during the inspection period. Tri-State did not report any exceedances of SO_2 limits during the inspection period. Annual emissions of SO_2 are calculated and reported as required. Operation and maintenance of the scrubber is conducted consistent with the requirements of Permit Condition 16.

Source is in compliance with this condition.

3.3 Nitrogen oxides (NO_x) emissions must not exceed the following limits:

3.3.1 **0.50 lb/MMBtu heat input, 30 consecutive boiler operating-day rolling average**, Colorado Construction Permit 12MF322-1 The Source must comply with Best Available Control Technology (BACT) requirements for NO_x. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

3.3.1.1 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.1.2 Compliance with the NO_x emission limitation is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day and a new 30 day average emission rate for nitrogen oxides is calculated to show compliance with the standard (40 CFR Part 60, §60.48Da(b)).

3.3.1.3 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.1.4 Compliance with this limit shall be monitored using the CEMS as required in Condition 3.8. The lb/MMBtu emission rate will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.3.2 6,752 tons of NO_x per year, Colorado Construction Permit 12MF322-1

3.3.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.8.

3.3.3 40 CFR Part 60, Subpart Da

3.3.3.1 For coal-derived solid fuels: **0.50 lb/MMBtu heat input**, 30-day rolling average (40 CFR Part 60, §60.44Da(a)(1) & §60.44Da(e)).

3.3.3.2 This NO_x emission limit applies at all times except during periods of startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(a)).

3.3.3.3 Compliance with the applicable NO_x emission limit requirements under 40 CFR Part 60, §60.44Da (Condition 3.3.3) is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30-boiler operating day rolling average emission rate for NO_x is calculated to demonstrate compliance with the standards (40 CFR Part 60, §60.48Da(b)).

3.3.3.4 Compliance with the applicable 30-boiler operating day rolling average for NO_x emission limits is determined by calculating the arithmetic average of all hourly emission rates for NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, or malfunction (40 CFR Part 60, §60.48Da(d)).

3.3.3.5 If the Source has not obtained the minimum quantity of emission data as required under 40 CFR Part 60, §60.49Da (Condition 3.3.3.6), compliance with the NO_x emission requirements in §60.44Da (Condition 3.3.3) for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in Section 7 of Method 19 of 40 CFR Part 60, Appendix A (40 CFR Part 60, §60.48Da(h)).

3.3.3.6 The Source shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring NO_x emissions discharged into the atmosphere (40 CFR Part 60, §60.49Da(c)(1)); or

If the Source has installed a NO_x emission rate CEMS to meet the requirements of 40 CFR Part 75 and is continuing to meet the ongoing requirements of 40 CFR Part 75, that CEMS may be used to meet the requirements of this section, except that the Source shall also meet the requirements of §60.51Da (Condition 3.9.2). Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in Subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75 (40 CFR Part 60, §60.49Da(c)(2)).

a. The Source, if not complying with an output based limit, shall install, calibrate, maintain, and operate a CEMS, and record the output of the system, for measuring the O_2 or CO_2 content of the flue cases at each location where NO_x emissions are monitored (40 CFR Part 60, §60.49Da(d)).

b. The CEMS shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, malfunction or emergency conditions, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments (40 CFR Part 60, §60.49Da(e)).

c. Additional CEMS requirements are described in Condition 3.8.

3.3.3.7 In conducting the performance tests required in 40 CFR Part 60, §60.8, the Source shall use as reference methods and procedures in the methods in 40 CFR Part 60, Appendix A or the methods and procedures as specified in §60.50Da, except as provided in §60.8(b). §60.8(f) does not apply to §60.50Da for NO_x. Acceptable alternative methods are given in §60.50Da(e) (40 CFR Part 60, §60.50Da(a)).

3.3.3.8 The Source shall determine compliance with the NO_x standard in 40 CFR Part 60, §60.44Da (Condition 3.3.3) as follows (40 CFR Part 60, §60.50Da(d)):

a. The appropriate procedures in Method 19 of Appendix A of 40 CFR Part 60 shall be used to determine the emission rate of NO_x (40 CFR Part 60, §60.50Da(d)(1)).

b. The continuous monitoring system in 40 CFR Part 60, §60.49Da(c) & (d) (Condition 3.3.3.6) shall be used to determine the concentrations of NO_x and CO_2 or O_2 (40 CFR Part 60, §60.50Da(d)(2)).

3.3.3.9 Reporting requirements associated with 40 CFR Part 60, Subpart Da are described in Condition 3.9.2.

3.3.4 0.28 lb/MMBtu, based on a 30-day rolling average, Colorado Regulation No. 23, Section IV.B.

3.3.4.1 The Source must maintain control equipment or operational practices required to comply with this limit and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained (Colorado Regulation No. 23, Section IV.A.3.).

3.3.4.2 The Source shall comply with 40 CFR Part 75 monitoring and recordkeeping requirements (see Condition 19) with the exception of the CEMS data substitution and bias adjustment requirements (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.3 At all times, the Source shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found in 40 CFR Part 75, except as described in Condition 3.3.4.2, to accurately measure SO_2, NO_x, diluents, and stack gas volumetric flow rate. The CEMS shall be used to determine compliance with the NO_x emission limit. The Source shall calculate emissions in the units of lb/MMBtu (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.4 In determining compliance with the NO_x regional haze limit, all periods of emissions shall be included, including startups, shutdowns, emergencies, and malfunctions (Colorado Regulation No. 23, Section V.A.1.a.).

3.3.4.5 For any hour in which fuel is combusted, the Source shall calculate hourly average NO_x concentrations in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR Part 75, except as described in Condition 3.3.4.2. These hourly averages shall be used to determine compliance in accordance with the averaging period as follows (Colorado Regulation No. 23, Section V.A.1.a.(i)):

a. Regional Haze limits with a 30-day averaging period: Before the end of each operating day, the Source shall calculate and record the 30-day rolling average emission rate in lb/MMBtu for all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 23, Section V.A.1.a.(i)(B)).

3.3.4.6 The Source must maintain records and follow the reporting requirements as described in Condition 3.10, as appropriate (Colorado Regulation No. 23, Section V.C. & D.).

3.3.5 Compliance calculations for NO_x requirements in Condition 0, with the exception of the annual emission limitation in Condition 3.3.2, shall be performed using one-hour average emission

rates as determined by the CEMS as required in Condition 2.7. For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average NO_x concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4. All hours for which there was valid data shall be used to calculate the 30-day rolling average (Colorado Regulation No. 3, Part C, Section V.C.5.).

3.3.5.1 All hours for which there was valid data, including emission data generated during startup, shutdown, and malfunction, shall be used in the 30-day rolling average calculations.

3.3.5.2 Compliance with the 30-day rolling average is monitored by calculating the arithmetic average of all hourly emissions rates for the 30 successive boiler operating days. A boiler operating day is any day in which fuel is fired in the unit for any period of time.

3.3.6 For purposes of monitoring compliance with the annual emission limitation in Condition 3.3.2, for any hour in which fuel is combusted in the unit, the Source shall program the DAHS to calculate lb/hr NO_x emissions in accordance with the requirements in Condition 19.1.8.2 and 40 CFR Part 75, including any replaced data, and the data shall be bias-adjusted, if warranted.

3.3.6.1 Hourly mass NO_x emissions (in lb/hr) shall be calculated by multiplying the hourly 40 CFR Part 75 NO_x lb/MMBtu value (which includes replaced or bias-adjusted data, as applicable) by the hourly heat input rate (MMBtu/hr) (which includes replaced and bias-adjusted data from the stack flow and % CO_2 measurements, as applicable). The hourly NO_x lb/MMBtu and heat input values are determined using the relevant equations in Appendix F of 40 CFR Part 75. The resulting NO_x lb/hr value is then multiplied by the unit operating time for that hour to produce a NO_x lbs value. Hourly NO_x mass emissions (lbs) shall be summed and divided by 2000 lb/ton to determine monthly NO_x emissions (in tons).

Compliance with the NOx limits is monitored using a CEMS. The NOx CEMS is operated and maintained consistent with the requirements of 40 CFR Part 60 and 40 CFR Part 75. Tri-State did not report any exceedances of NOx limits during the inspection period. Annual emissions of NOx are calculated and reported as required. Annual NOx emissions records were provided and are summarized in the table below. A review of records provided indicates that Tri-State has not exceeded the annual NOx emissions limit.

Tri-State G&T Craig Station Unit 3 Annual Coal NOx Emissions	
Period	**Reported Annual Emissions (tons/yr)**
	NOx
3/2023-2/2024	2,209.7
1/2024-12/2024	1,485.0
2/2024- 1/2025	1,353.0
Limits:	*6,752*

Source is in compliance with this condition.

3.4 Carbon Monoxide (CO)

3.4.1 Colorado Construction Permit 12MF322-1

3.4.1.1 Good combustion practices shall be used to limit CO emissions to 1.25 lb/MMBtu on an 8-hour rolling average. The Source must comply with Best Available Control

Technology (BACT) requirements for CO. The Division and the EPA have determined that this limit meets the BACT requirements and that the BACT limits apply at all times, as specified.

a. Compliance with this limit shall be monitored using the CO CEMS as required by Condition 3.4.2. The lb/MMBtu emission factor will be calculated using a 5 percent CO_2 diluent cap when CO_2 measurements are less than 5 percent.

3.4.1.2 4,332 tons of CO per year

a. Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be monitored using the CEMS as required by Condition 3.4.2.

b. Monthly emissions shall be calculated by multiplying the average monthly emission rate in lb/MMBtu by the total monthly heat input in mmBtu, then converting to tons by dividing by 2000 lb//ton.

3.4.2 Compliance with the CO limits in Condition 3.4 must be monitored using a CO CEMS in accordance with the requirements of Conditions 3.8 and 19, and in accordance with the following:

3.4.2.1 For any hour in which fuel is combusted in the unit, the Source shall calculate the hourly average CO concentrations in units of lb/MMBtu in accordance with the requirements of 40 CFR Part 75 (see Condition 19), except that replaced data shall not be included and the data shall not have been bias-adjusted. Replaced data shall be reported as monitor downtime in the quarterly reports required by Condition 19.4.

Compliance with the CO limits is monitored using a CEMS. The CO CEMS is operated and maintained consistent with the requirements of 40 CFR Part 60 and 40 CFR Part 75. Tri-State did not report any exceedances of CO limits during the inspection period. Annual emissions of CO are calculated and reported as required. Annual CO emissions records were provided and are summarized in the table below. A review of records provided indicates that Tri-State has not exceeded the annual CO emissions limit.

Tri-State G&T Craig Station Unit 3 Annual CO Emissions	
Period	**Reported Annual Emissions (tons/yr)**
	CO
3/2023-2/2024	656.7
1/2024-12/2024	396.2
2/2024- 1/2025	351.1
Limits:	*4,332*

Source is in compliance with this condition.

3.5 Volatile Organic Compounds (VOC), Lead (Pb), Sulfuric Acid Mist (SAM), and Fluorides

3.5.1 The Source shall not cause to be emitted into the atmosphere VOC, Pb, SAM, or fluorides in excess of the following limits:

3.5.1.1 VOC: 58 tons per year

3.5.1.2 Lead (Pb): 0.054 tons per year

3.5.1.3 Sulfuric Acid Mist (SAM): 0.10 tons per year

3.5.1.4 Fluorides: 4.47 tons per year

3.5.2 Compliance with the annual limits in Condition 3.5.1 shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data. Monthly emissions shall be calculated using actual fuel heating values as determined by the required testing in Condition 3.7.3, the actual fuel usage, and Division approved emission factors (the current emission factor as listed in Table 3, AP-42, EPRI, stack testing, or other Division-approved methods in accordance with Colorado Regulation No. 3, Part A, Section II.B.1.), in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{Ton}{month} = Emission\ Factor\ \left[\frac{lb}{MMBtu}\right] * Fuel\ Heat\ Content\ \left[\frac{MMBtu}{ton\ coal}\right] * Fuel\ Use\ \left[\frac{ton\ coal}{month}\right] * \frac{1\ ton}{2000\ lb}$$

Annual emissions of VOC, Lead (Pb), Sulfuric Acid Mist (SAM) and Fluorides are calculated using the specified methodology on a rolling 12-month total as required. Annual emissions records of VOC, Lead, Sulfuric Acid Mist and Fluorides were provided and are summarized in the table below. A review of records submitted indicates that the VOC, Lead, Sulfuric Acid Mist and Fluorides emissions limits have not been exceeded.

Tri-State G&T Craig Station Unit 3 Annual VOC, Pb, SAM and Fluorides Emissions				
Period	**Reported Annual Emissions (tons/yr)**			
	VOC	**Pb**	**SAM**	**Fluorides**
3/2023-2/2024	32.4	0.012	0.05	1.05
1/2024-12/2024	23.0	0.008	0.04	0.74
2/2024- 1/2025	21.4	0.007	0.04	0.69
Limit:	*58*	*0.054*	*0.10*	*4.47*

Source is in compliance with this condition.

3.6 Opacity

3.6.1 Colorado Construction Permit 12MF322-1

The Source must comply with Best Available Control Technology (BACT) requirements for opacity. The Division and the EPA have determined that the following limits meet the BACT requirements and that the BACT limits apply at all times, as specified.

3.6.1.1 Except as provided for in Conditions 3.6.1.2 and 3.6.1.3, the Source may not allow or cause the emission into the atmosphere any gases in excess of 10 percent (%) opacity, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

3.6.1.2 During periods of startup and shutdown, opacity must not exceed 20%, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

a. "Startup" means the setting in operation of any air pollution source for any purpose. Startup commences when the ID/FD fans are started with the intent to purge the furnace prior to returning Unit 3 to service. Startup ends at such time when either a third scrubber reactor is placed online or when the average scrubber inlet temperature reaches 250 degrees Fahrenheit, or when the startup is stopped for any reason and the unit drops to zero load.

b. "Shutdown" means the cessation of operation of any air pollution source for any purpose. The cessation of operation for Unit 3 begins when the command signal is initiated by the unit operator to shutdown the unit and ends when fuel is no longer being fired and the fans have been shut off.

3.6.1.3 During the five-day period following the return of each and every baghouse compartment to service following bag replacement, reattachment, and retensioning, up to 20% opacity shall be allowed for no more than a total of 30 six-minute periods during each five-day period following such work, as averaged over each separate six-minute period within an hour, beginning each hour on the hour, except for one six-minute period per hour of not more than 27% opacity.

Unit 3 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. No exceedances of the opacity limits were reported during the inspection period. Opacity in excess of any standard is reported on quarterly EERs as required. The source was not operating during the inspection and no visible emissions were observed.

Source is in compliance with this condition.

3.6.2 Colorado Regulation No. 1

3.6.2.1 Except as provided in Condition 3.6.2.2, the Source may not allow or cause the emission into the atmosphere of any air pollutant that is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference test method for visible emissions measurement is EPA Method 9 (40 CFR Part 60, Appendix A (July, 1992)) (Colorado Regulation No. 1, Section II.A.1.).

3.6.2.2 The Source may not allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity for a period or periods aggregating more than six minutes in any sixty consecutive minutes (Colorado Regulation No. 1, Section II.A.4.).

Unit 3 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. No exceedances of the opacity limits were reported during the inspection period. The source was not operating during the inspection and no visible emissions were observed.

Source is in compliance with this condition.

3.6.3 Colorado Regulation No. 6 [State-only requirement]

3.6.3.1 The Source must not discharge, or cause the discharge into the atmosphere any particulate matter which is in excess of 20% opacity (Colorado Regulation No. 6, Part B. Section II.C.3.). This standard applies at all times except during periods of startup, shutdown, or malfunction

3.6.3.2 In addition, the requirements of Colorado Regulation No. 6, Part A, Subpart A; General Provisions, apply. These requirements include the 40 CFR Part 60, Subpart A, General Provisions which include but are not limited to the requirements described in Condition 18.

Unit 3 is equipped with COMS as required. Opacity in excess of any standard is reported on quarterly EERs as required. No exceedances of the opacity limits were reported during the inspection. The source was not operating during the inspection and no visible emissions were observed.

Source is in compliance with this condition.

3.6.4 Compliance with the opacity emissions limitations in Condition 3.6 shall be monitored on a continuous basis using data from the current Continuous Opacity Monitoring System (COMS) or an EPA and Division-approved COMS at an alternative location, and may be verified on an intermittent basis by EPA Method 9, per the procedures outlined in 40 CFR Part 60, Appendix A-4.

3.6.4.1 The requirements for the COMS system are outlined in Conditions 3.8 and 19.

3.6.4.2 In the event that EPA Method 9 visual opacity observation are used by the Source to verify compliance, an inspection for visible emissions must be performed at least twice per day: once in the morning and once in the afternoon, during daylight hours. During such inspections, if visible emissions other than steam persist for more than six (6) minutes, a certified observer must perform an EPA Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A) within a reasonable amount of time, not to exceed one-half hour. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows that the opacity is less than the opacity limit.

a. All Method 9 readings must be conducted by a certified observer.

b. Records of current observer certification and the results of all visible emission inspections and Method 9 readings must be kept on site and made available for Division inspection upon request. Copies of any observations exceeding the applicable standard(s) must be submitted with the next scheduled report.

Compliance with opacity limits is monitored with a COMS. The COMs is operated and maintained consistent with the requirements of 40 CFR Part 60. The source did not monitor compliance with opacity with EPA Method 9 during the inspection period. The source was not operating at the time of the inspection. No visible emissions were observed during the inspection. (see Conditions 3.8 and 19)

Source is in compliance with this condition.

3.7 Coal Requirements

3.7.1 Consumption of coal must not exceed 1,897,344 tons per year (Colorado Construction Permit 12MF322-1).

3.7.1.1 Compliance with the annual throughput limit shall be determined on a rolling twelve-month total. By the end of each new month a new twelve-month total is calculated based on the previous twelve-months' data.

3.7.2 Annual records of actual coal consumption must be maintained by the Source and made available for Division inspection upon request. Natural gas, propane, and fuel oil are used at startup, shutdown, upset, and for flame stabilization. The use of any other fuel may require this Operating Permit to be opened for modification prior to the use of the alternative fuel. As-fired belt scales will be used to monitor coal combusted in the boiler. The belt scales must be calibrated on an annual basis using certified standards. Records of the certifications and calibrations must be maintained for Division inspection upon request for a minimum of five years.

3.7.3 Coal must be sampled quarterly, at a minimum, in accordance with the requirements described in Condition 20.

Coal consumption is tracked by the source on a monthly and 12-month rolling basis as required. The 12-month rolling total coal consumption records were provided for the inspection period and are summarized in the table below. The facility uses coal delivery records to comply with this condition, and maintains copies of its coal suppliers' annual scale calibrations. A review of records provided indicates that Tri-State has not exceeded the annual coal consumption limit.

Coal samples are taken daily and analyzed for ash, heat, and sulfur content daily for each electric generating unit at Craig station.

Tri-State G&T Craig Station Unit 3 Annual Coal Consumption	
Period	**Reported Annul Coal Consumption (tons/yr)**
3/2023-2/2023	1,072,611
1/2024-12/2024	739,506
2/2024- 1/2025	685,170
Limit:	*1,897,344*

Source is in compliance with this condition.

3.8 Continuous Emissions Monitoring Systems (CEMS)

For this emission unit, the Source must install, certify, and operate CEMS for measuring opacity (COMS), SO_2, NO_x, (including diluent gas: either CO_2 or O_2), CO, CO_2, and volumetric flow (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A, and Colorado Regulation No. 1, Section IV.B.1., 2., and 3.). The CEMS must meet the requirements of Section II, Condition 19 and Section III of this Operating Permit.

Note that at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

This source has installed, certified and maintains a CEMS in accordance with the requirements of 40 CFR 60 and 40 CFR 75. Unit 3 is equipped with opacity, SO_2, NO_x, CO_2, CO and flow monitors. In addition, each inlet (inlet A, B, C and D) to the FGD is equipped with SO_2 and CO_2 monitoring systems to determine inlet SO_2 lbs/mmBtu rates. Those rates are compared to outlet emission rates to determine reduction efficiency of the FGD. Passing RATAs were performed on each CEMS on June 14, 2024. This RATA testing was reviewed and approved by the Division on August 21, 2024. RATAs were also performed on each inlet CEMS for each test program. The source performs Part 75 Linearity Checks on a quarterly basis as required. Daily calibrations are performed as required. Compliance with 40 CFR 60 CEMS requirements is assumed by complying with Part 75 requirements.

Source is in compliance with this condition.

3.9 40 CFR Part 60, Subpart Da

3.9.1 Affirmative defense for exceedance of emissions limit during malfunction, 40 CFR Part 60, §60.48Da(s)

3.9.1.1 In response to an action to enforce the standards set forth in 40 CFR Part 60, Subpart Da, §60.42Da, §60.43Da, §60.44Da, and §60.45Da, the Source may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by a malfunction, as defined at 40 CFR Part 60, §60.2. Appropriate penalties may be assessed, however, if the Source fails to meet the burden of proving

all of the requirements in the affirmative defense as specified in 40 CFR Part 60, §60.48Da(s)(1) and (2). The affirmative defense shall not be available for claims for injunctive relief (40 CFR Part 60, §60.48Da(s)).

3.9.2 Reporting requirements, 40 CFR Part 60, §60.51Da

For all reports required in this condition the Source shall submit the written reports required under 40 CFR Part 60, Subparts Da and A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period (40 CFR Part 60, §60.51Da(j)).

The Source may submit electronic quarterly reports for SO_2 and/or NO_x and/or opacity in lieu of submitting the written reports required under 40 CFR Part 60, §60.51Da(b) and (j). The format of each quarterly electronic report shall be coordinated with the Administrator. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the Source indicating whether compliance with the applicable emissions standards and minimum data requirements of 40 CFR Part 60, Subpart Da was achieved during the reporting period (40 CFR part 60, §60.51Da(k)).

Note that per Colorado Regulation No. 6, Part A, the Division has been delegated authority to act as the Administrator for Subpart Da.

3.9.2.1 For SO_2, NO_x, PM, and NO_x plus CO emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) shall be reported to the Division, as applicable (40 CFR Part 60, §60.51Da(a)).

3.9.2.2 For SO_2 and NO_x the information contained in 40 CFR Part 60, §60.51Da(b)(1) through (9) shall be reported to the Division for each 24-hour period (40 CFR Part 60, §60.51Da(b)).

3.9.2.3 If the minimum quantity of emission data as required by 40 CFR Part 60, §60.49Da is not obtained for any 30 successive boiler operating days, the information in §60.51Da(c)(1) through (5) as obtained under the requirements of §60.48Da(h) shall be reported to the Division for that 30-day period (40 CFR Part 60, §60.51Da(c)).

3.9.2.4 In addition to the applicable requirements in §60.7, the Source shall submit excess emission reports for any Method 9 opacity observation emissions in excess of the requirements of §60.43c(c) from the facility occur during the reporting period and shall maintain records according to the requirements specified in §60.51Da(d)(1) (40 CFR Part 60, §60.51Da(d)).

3.9.2.5 For any periods for which opacity, SO_2, or NO_x emissions data are not available, the Source shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation for the control system and affected facility before and following the period of data unavailability (40 CFR Part 60, §60.51Da(f)).

3.9.2.6 The Source shall submit a signed statement indicating whether (40 CFR Part 60, §60.51Da(h)):

a. The required CEMS calibration, span, and drift checks or other periodic audits have or have not been performed as specified (40 CFR Part 60, §60.51Da(h)(1)).

b. The data used to show compliance was or was not obtained in accordance with approved methods and procedures of 40 CFR Part 60, Subpart Da and is representative of plant performance (40 CFR Part 60, §60.51Da(h)(2)).

c. The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable (40 CFR Part 60, §60.51Da(h)(3)).

d. Compliance with the standards has or has not been achieved during the reporting period (40 CFR Part 60, §60.51Da(h)(4)).

3.9.2.7 For the purposes of the reports required under 40 CFR Part 60, §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Division each calendar quarter (40 CFR Part 60, §60.51Da(i)).

3.9.3 Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

Tri-State is submitting NSPS Subparts Dc and A reports quarterly attached to excess emissions reports. No deviations from NSPS Subparts Dc and A requirements were reported during the inspection period.

Source is in compliance with this condition.

3.10 Colorado Regulation No. 23, Regional Haze

3.10.1 Craig Unit 3 will close no later than December 31, 2029 (Colorado Regulation No. 23, Section IV.F.1.f.).

3.10.2 Colorado Regulation No. 23, Sections V.C. and D., Regional Haze Recordkeeping and Reporting Requirements

3.10.2.1 The Source shall maintain the following records for a minimum of five years (Colorado Regulation No. 23, Section V.C.):

a. All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable, and any field data sheets from testing (Colorado Regulation No. 23, Section V.C.1.).

b. Records of QA and QC activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Parts 60, 63, or 75 (Colorado Regulation No. 23, Section V.C.2.).

c. Any other records required by 40 CFR Parts 60, Subpart F, Section 60.65, 63, Subpart LLL, 64 or 75 (Colorado Regulation No. 23, Section V.C.3.).

3.10.2.2 The Source shall submit semiannual excess emissions reports no later than the 30th day following the end of each semiannual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, §60.7(c) (Colorado Regulation No. 23, Section V.D.).

3.10.2.3 The Source shall submit reports of any required performance stack tests for PM to the division with 60 calendar days after completion of the test (Colorado Regulation No. 23, Section V.D.).

3.10.2.4 The Source shall submit semiannual reports of any excursions under the approved CAM plan in accordance with the schedule specified in this Title V permit (Colorado Regulation No. 23, Section V.D.).

3.10.2.5 The owners or operators of units in Colorado Regulation No. 23, Sections IV.D. or IV.F. must submit APENs to the Division within 90 days of the applicable, or actual if sooner, closure date (Colorado Regulation No. 23, Section V.D.).

Tri-State maintains records for five years as required. Excess Emissions reports are submitted quarterly and contain the required information. Stack testing reports for PM emissions tests are submitted within 60 days as required. CAM excursions are reported as required in the Semi-Annual Monitoring Reports. APENs for the facility are submitted as required and are up to date.

Source is in compliance with this condition.

3.11 Acid Rain

This unit is subject to the Title IV Acid Rain Requirements. As specified in 40 CFR Part 72.72(b)(1)(viii), the acid rain permit requirements shall be a complete and segregable portion of the Operating Permit. As such the requirements are found in Section III of this permit.

The source is subject to the Acid Rain Program ("ARP"). Section III of the permit outlines the ARP requirements. Compliance with the reporting requirements is monitored through the Clean Air Markets Division (CAMD) of EPA.

Without evidence to the contrary, source is presumed to be in compliance with this condition.

3.12 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal – and Oil-Fired Electric Utility Steam Generating Units

Unit 3 is subject to the requirements of 40 CFR Part 63, Subpart UUUUU; this rule is also known as the mercury and air toxics (MATS) rule. Requirements pertaining to the MATS rule are described in Condition 5.

Source is in compliance with the requirements of 40 CFR 63, Subpart UUUUU, see Condition 5.

Source is in compliance with this condition.

3.13 Compliance Assurance Monitoring (CAM)

Unit 3 is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM and PM_{10} limitations in Condition 3.1, the SO_2 limitations in Condition 3.2, and the NO_x limitations in Condition 0. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendices H, K, And M.

Source is in compliance with CAM requirements, See conditions 3.1, 3.2, and 3.3. CAM requirements are monitored consistent with the requirements in Condition 22 and Appendices H, K, and M.

Source is in compliance with this condition.

4. B001, B002, and B003 – Units 1, 2, and 3: Natural Gas, Propane, and Fuel Oil

The Source must maintain records of annual usage of natural gas, propane, and fuel oil, and the associated annual heat contents of each, as appropriate. If, for each boiler, the total annual heat content of these fuels combined exceeds 5% of the total heat content of all fuels combusted, this Operating Permit shall be reopened to incorporate the appropriate applicable requirements for combusting combined/alternative fuels.

Tri-State maintains records of annual fuel usage and reports fuel use on annual APENs as required. The boilers operate almost exclusively on coal. The annual heat content of alternative fuels to coal did not exceed 5%, and there is no reason to reopen the permit.

Source is in compliance with this condition.

5. 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units

Units 1, 2 and 3 are subject to the requirements of MACT UUUUU, also known as the mercury and air toxics (MATS) rule. The applicable requirements under the MATS rule are as follows. The requirements apply to Units 1, 2, and 3 unless otherwise specified.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart UUUUU published in the Federal Register on September 9, 2020. However, if revisions to this Subpart are published at a later date, the Source is subject to the applicable revised requirements.

As of the date of publication of this Operating Permit, Units 1, 2, and 3 all: comply with the low EGU emitter (LEE) requirements for PM; use SO_2 as a surrogate for HCl emissions and use an SO_2 CEMS; Units 1 and 2 use mercury (Hg) CEMS, and Unit 3 uses Hg sorbent traps to monitor compliance with the Hg emission limitations.

5.1 §63.9991 What emission limitations, work practice standards and operating limits must I meet?

5.1.1 At all times, the Source shall meet each emission limit and work practice standard in Table 1 through 3 of 40 CFR Part 63, Subpart UUUUU, as applicable, except as provided under §63.10009, and shall meet each operating limit in Table 4 of Subpart UUUUU, as applicable (40 CFR Part 63, §63.9991(a)(1) and (2)). These requirements are as follows:

5.1.2 The Source is subject to the following requirements from Table 2 of Subpart UUUUU:

Table 2.1 Requirements	Pollutant	Emission limits and work practice standards	Specific requirements for test methods in Table 5 of Subpart UUUUU
a.	Filterable PM	0.03 lb/MMBtu OR 0.3 lb/MWh (gross output)	Collect minimum of 1 dscm per run.
b.	Sulfur dioxide (SO_2)[1]	0.2 lb/MMBtu OR 1.5 lb/MWh	SO_2 CEMS
c.	Mercury (Hg)	1.2 lb/TBtu OR 0.013 lb/GWh	LEE testing for 30 days with a sampling period consistent with that given in 5.2.1 of Appendix A to Subpart UUUUU per Method 30B at Appendix A-8 to 40 CFR Part 60 run or HG CEMS or sorbent trap monitoring system only.

Table 4 - Subpart UUUUU Table 2 Requirements

Tri-State reported continuous compliance with applicable PM, SO2 and Hg emissions requirements for Units 1, 2 and 3 during the compliance period.

Tri-State provided the Division with a request to apply the Alternative Hg limit of 0.011 lb/GWh on a 90-day rolling average as allowed by 40 CFR 63.9991(a)(1) that was received on May 2, 2023. The Division granted this request with an email on May 12, 2023 beginning when Unit 1 restarted after an outage on May 14, 2023.

Source is in compliance with this condition.

5.1.3 The Source shall conduct a tune-up of the EGU burner and combustion controls at least each 36 calendar months, as specified in §63.10021(e) (40 CFR part 63, Table 3.1).

5.1.4 The following work practice standards are required during startup (40 CFR Part 63, Table 3.3):

5.1.4.1 Note: The following two definitions of startup apply to this condition, as applicable (40 CFR Part 63, §63.10042):

a. Either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup; or

b. The period in which operation of an EGU is initiated for any purpose. Startup begins with either the firing of any fuel in an EGU for the purpose of producing electricity or useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (other than the first-ever firing of fuel in a boiler following construction of the boiler) or for any other purpose after a shutdown event. Startup ends 4 hours after the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. Any fraction of an hour in which startup occurs constitutes a full hour of startup.

5.1.4.2 The Source has the option of complying using either of the following work practice standards (40 CFR Part 63, Table 3.3.a):

a. If the Source chooses to comply using paragraph (1) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during startup. Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). For startup of a unit, the Source must use clean fuels as defined in §63.10042 for ignition. Once the Source converts to firing coal, residual oil, or solid oil-derived fuel, the Source must engage all of the applicable control technologies except dry scrubber and SCR. The Source must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The Source must comply with all applicable emissions limits at all times except for periods that meet the applicable definitions of startup and shutdown in this Subpart UUUUU. The Source must keep records during startup periods. The Source must provide reports concerning activities and startup periods, as specified in §63.10011(g) and §63.10021(h) and (i) (Conditions 5.8.8 and 5.8.9). If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.a(1)).

b. If the Source chooses to comply using paragraph (2) of the definition of "startup" in §63.10042 (see note in Condition 5.1.4), the Source shall operate all CMS during

startup. The Source shall also collect appropriate data, and shall calculate the pollutant emission rate for each hour of startup. For startup of an EGU, the Source shall use one or a combination of the clean fuels defined in §63.10042 to the maximum extent possible, taking into account considerations such as boiler or control device integrity, throughout the startup period. The Source shall have sufficient clean fuel capacity to engage and operate the PM control device within one hour of adding coal to the unit. The Source shall meet the startup period work practice requirements as identified in §63.10020(e) (Condition 5.7.5). Once the Source stats firing coal, emissions shall be vented to the main stack(s). The Source shall comply with the applicable emission limits beginning with the hour after startup ends. The Source shall engage and operate the PM control(s) within 1 hour of first firing of coal. The Source shall start all other applicable control devices as expeditiously as possible, considering safety and manufacturer/supplier recommendations, but, in any case, when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than Subpart UUUUU that require operation of the control devices (40 CFR Part 63, Table 3.3.a(2)).

5.1.4.3 If the Source chooses to use just one set of sorbent traps to demonstrate compliance with the applicable emission limit, the Source shall comply with the limit at all times except for startup and shutdown periods (40 CFR Part 63, Table 3.3.c).

5.1.4.4 The Source shall collect monitoring data during startup periods as specified in §63.10020(a) and (e) (Condition 5.7.1 and 5.7.5). The Source shall keep records during startup periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). The Source shall provide reports concerning activities and startup periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning startup periods as follows: For startup periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for startup periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR §63.10031(i) (Condition 5.12.9) (40 CFR Part 63, Table 3.3.d).

5.1.5 The following work practice standards are required during shutdown (40 CFR Part 63, Table 3.4):

5.1.5.1 The Source shall operate all continuous monitoring systems (CMS) during shutdown. The Source shall collect appropriate data, and shall calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used.

5.1.5.2 While firing coal, the Source shall vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal being fed into the EGU and for as long as possible thereafter considering operational and safety concerns. In any case, the Source shall operate the controls when necessary to comply with other standards made applicable to the EGU by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices.

5.1.5.3 If, in addition to the fuel used prior to the initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel shall be one or a combination of the clean fuels defined in §63.10042 and shall be used to the maximum extent possible, taking into account considerations such as not compromising boiler or control device integrity.

5.1.5.4 The Source shall comply with all applicable emission limits at all times except during startup and shutdown periods at which time the Source shall meet the requirements of the work practices described in Conditions 5.1.4 and 5.1.5. The Source shall collect

monitoring data during shutdown periods, as specified in §63.10020(a) (Condition 5.7.1). The Source shall keep records during shutdown periods, as provided in §63.10032 and §63.10021(h) (Conditions 5.13 and 5.8.8). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. The Source shall provide reports concerning activities and shutdown periods, as specified in §63.10011(g), §63.10021(i), and §63.10031. If the Source elects to use paragraph (2) of the definition of startup in 40 CFR §63.10042, the Source must report the applicable information in 40 CFR §63.10031(c)(5) (Condition 5.12.3) concerning shutdown periods as follows: For shutdown periods that occur on or prior to December 31, 2023, in PDF files in the semiannual compliance report; for shutdown periods that occur on or after January 1, 2024, quarterly, in PDF files, according to 40 CFR 63.10031(i) (Condition 5.12.9).

5.1.6 As provided in 40 CFR Part 63, §63.6(g), the Administrator may approve the use of an alternative to the work practice standards required in §63.9991 (Condition 5.1) (40 CFR Part 63, §63.9991).

PM: Quarterly performance testing for PM was performed on Unit 1 and Unit 2 for 36 months beginning in the second quarter of 2015 and concluding in the first quarter of 2018 in accordance with the LEE provisions of MATS. PM testing for Unit 1 and Unit 2 is now required every 36 months. PM testing on Unit 1 was completed on January 18, 2024 and on Unit 2 on January 18, 2024. The Division reviewed and approved this testing on February 26, 2024. Quarterly performance testing for PM was performed on Unit 3 for 36 months beginning in the third quarter of 2015 and concluding in the second quarter of 2018 in accordance with the LEE provisions of MATS. PM testing for Unit 3 is now required every 36 months. PM Testing on Unit 3 was completed on June 15, 2024. The Division reviewed and approved the June 15, 2024 testing on August 21, 2024. The dates those tests were performed, the results of those tests, and the dates in which the test reports were submitted to CDX are shown in the Reports section of this inspection report. All tests have been approved by the Division as adequate demonstrations of LEE status.

HCl: Tri-State monitors SO_2 as a surrogate for HCl using SO_2 CEMS certified and maintained in accordance with the applicable provisions of 40 CFR 75. Tri-State reported no exceedances of the 0.20 lb/MMBtu limit since the compliance date of the rule.

Hg: Annual Hg performance testing was conducted on Unit 1 and Unit 2 to demonstrate LEE status for each EGU until July 2018. Unit 1 and Unit 2 failed to achieve LEE status based on the July 2018 testing. Subsequent to the July 2018 testing Tri-State conducted quarterly Hg testing on Unit 1 and Unit 2 consistent with the requirements of the MATS Rule until Continuous Mercury Monitoring Systems (CMMS) were installed on each of the Units with monitor certification having been completed on February 19, 2019 and February 20, 2019. Unit 1 is equipped with a Tekran Series 3300, Serial Number 6083 CMMS and Unit 2 is equipped with a Tekran Series 3300, Serial Number 6082 CMMS. The most recent RATAs on the Unit 1 and Unit 2 mercury monitors were conducted on June 14, 2024 and June 11, 2024 respectively. The Division reviewed and approved the results of these RATAs on August 21, 2024. The CMMS are certified and maintained in accordance with the applicable provisions of 40 CFR 75 and 40 CFR 63. Tri-State certified continuous compliance with the standard in their most recent Quarterly Compliance Certifications reporting no violations of an emission standard. No exceedances of the Alternative Hg limit of 0.011 lb/GWh on a 90-day rolling average have been reported for Unit 1 since the Division approved use of the Alternative limit on May 12, 2022. No exceedances of the 30-day rolling average emission limit of 0.013 lb/GWh have been reported for Unit 2. No excessive monitor downtime was reported for Unit 1.

Tri-State provided the Division with a request to apply the Alternative Hg limit of 0.011 lb/GWh on a 90-day rolling average as allowed by 40 CFR 63.9991(a)(1) that was received on May 2, 2023. The Division granted this request with an email on May 12, 2023 beginning when Unit 1 restarted after an outage on May 14, 2023.

According to Tri-State's MATS reporting, Unit 1 was tuned on November 11, 2022; Unit 2 was tuned on November 7, 2023; Unit 3 was tuned on August 2, 2024. None of the EGU's employ a neural network and thus each unit must be tuned within 36 calendar months of the last tune.

Tri-State complies with the work practice standards in Table 3.3.a and 3.4 as required. Each unit complies with Paragraph 1 of Table 3.3.a and uses clean fuels (natural gas or diesel) for startup. Craig Station uses the proposed MATS technical correction language as guidance for the compliance report, which indicates that reporting of startup/shutdown data is required only when paragraph 2 of the definition of "startup" in §63.10042 is followed. Controls are set into operation as required following startup. Records and monitoring data are maintained as required. Monitors are maintained and operated as required during shutdown.

Source is in compliance with this condition.

5.2 §63.10000 What are my general requirements for complying with this subpart?

5.2.1 The Source shall be in compliance with the emission limits and operating limits in Subpart UUUUU. These limits apply at all times except during periods of startup and shutdown; however the Source is required to meet the work practice requirements, items 3 and 4, in Table 3 of Subpart UUUUU (Conditions 5.1.4 and 5.1.5) during periods of startup or shutdown (40 CFR Part 63, §63.10000(a)).

5.2.2 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the EPA Administrator which may include but is not limited to monitoring results, review of operation and maintenance procedure, review of operation and maintenance records, and inspection of the source (40 CFR Part 63,§63.10000(b)).

5.2.3 Initial performance testing is required for all pollutants to demonstrate compliance with the applicable emission limits (40 CFR Part 63, §63.10000(c)(1)).

5.2.3.1 The Source may conduct initial performance testing in accordance with §63.10005(h) (Condition 5.3.6) to determine whether the EGU qualifies as a low emitting EGU (LEE) for one or more applicable emission limits, except as otherwise provided in paragraphs §63.10000(c)(1)(i)(A) and (B) (Conditions 5.2.3.1.a. and b.) (40 CFR Part 63, §63.10000(c)(1)(i)).

a. Except as provided in §63.10000(c)(1)(i)(c) (Condition 5.2.3.1.c.), the Source may not pursue the LEE option if the EGU is equipped with a main stack and a bypass stack or bypass duct configuration that allows the effluent to bypass any pollutant control device (40 CFR Part 63, §63.10000(c)(1)(i)(A)).

b. The Source may not pursue the LEE option for Hg if the EGU is new (40 CFR Part 63, §63.10000(c)(1)(i)(B)).

c. The Source may pursue the LEE option provided that (40 CFR Part 63, §63.10000(c)(1)(i)(c)):

(i) The EGU's control device bypass emissions are measured in the bypass stack or duct, or the control device bypass exhaust is routed through the EGU main stack so that emissions are measured during the bypass event (40 CFR Part 63, §63.10000(c)(1)(i)(c)(1)); or

(ii) Except for hours during which only clean fuel is combusted, the Source bypasses the EGU control device only during emergency periods for no more than a total of 2 percent (%) of the EGU's annual operating hours; the Source uses clean fuels to the maximum extent possible during an emergency period; and the Source prepares and submits a report describing the emergency event, its cause, corrective action taken, and estimates of emissions released during the emergency event. The Source shall include these emergency emissions along with performance test results in assessing whether the EGU maintains LEE status (40 CFR Part 63, §63.10000(c)(1)(i)(c)(2)).

5.2.3.2 For a qualifying LEE for Hg emissions limits, the Source shall conduct a 30-day performance test using Method 30B at least once every 12 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(ii)).

5.2.3.3 For a qualifying LEE of any other applicable emissions limits, the Source shall conduct a performance test at least once every 36 calendar months to demonstrate continued LEE status (40 CFR Part 63, §63.10000(c)(1)(iii)).

5.2.3.4 If the EGU does not qualify as a LEE for total non-mercury HAP metals, individual non-mercury HAP metals, or filterable PM, the Source shall demonstrate compliance through an initial performance test and shall monitor continuous performance through either the use of a PM continuous parametric monitoring system (PM CPMS), a PM CEMS, or, for an existing EGU, compliance performance testing repeated quarterly (40 CFR Part 63, §63.10000(c)(1)(iv)).

5.2.3.5 If the EGU does not qualify as a LEE for hydrogen chloride (HCl), the Source may demonstrate initial and continuous compliance through use of an HCl CEMS, installed and operated in accordance with Appendix B of Subpart UUUUU. As an alternative to HCl CEMS, the Source may demonstrate initial and continuous compliance by conducting an initial and periodic quarterly performance stack test for HCl. If the EGU uses wet or dry flue gas desulfurization technology (this includes limestone injection into a fluidized bed combustion unit), the Source may apply a second alternative to HCl CEMS by installing and operating a SO_2 CEMS installed an operated in accordance with 40 CFR part 75 to demonstrate compliance with the applicable SO_2 emission limit (40 CFR Part 63, §63.10000(c)(1)(v)).

5.2.3.6 If the EGU does not qualify as a LEE for Hg, the Source shall demonstrate initial and continuous compliance through use of a Hg CEMS or a sorbent trap monitoring system, in accordance with Appendix A of Subpart UUUUU (40 CFR Part 63, §63.10000(c)(1)(vi)).

a. The Source may choose to use separate sorbent trap monitoring systems to comply with Subpart UUUUU: one sorbent trap monitoring system to demonstrate compliance with the numeric mercury emissions limit during periods other than startup or shutdown, and the other sorbent trap monitoring system to report average mercury concentration during startup periods or shutdown periods (40 CFR Part 63, §63.10000(c)(1)(vi)(A)).

b. The Source may choose to use one sorbent trap monitoring system to demonstrate compliance with the mercury emission limit at all times (including startup and shutdown periods) and to report average mercury concentration. The Source shall follow the startup or shutdown requirements that follow and are described in Table 3 of Subpart UUUUU (Conditions 5.1.3, 5.1.4, and 5.1.5) (40 CFR Part 63, §63.10000(c)(1)(vi)(B)).

5.2.4 If the Source demonstrates compliance with any applicable emissions limit through use of a CMS, where a CMS includes CPMS and CEMS, the Source shall develop a site-specific monitoring plan and submit it, if requested, at least 60 days before the initial performance

evaluation (where applicable) of the CMS. This requirement also applies if the Source elects to petition the Administrator for alternative monitoring parameters under §63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plants that apply to CEMS and CPMS prepared under Appendix B to 40 CFR Part 60 or Part 75, and that meet the requirements of §63.10010 (Condition 5.6). Using the process described in §63.8(f)(4), the Source may request approval of monitoring system quality assurance and quality control procedures to those specified in this condition and, if approved, include those in the site-specific monitoring plan. The monitoring plan shall address the provisions in §63.10000(d)(2) through (5) (40 CFR Part 63, §63.10000(d)(1)).

5.2.5 As part of the demonstration of continuous compliance, the Source shall perform periodic tune-ups of the EGU according to §63.00021(e) (Condition 5.8.4) (40 CFR Part 63, §63.10000(e)).

5.2.6 Except as provided in §63.10000(n) (Condition 5.2.16), the Source shall be subject to the requirements of Subpart UUUUU for at least 6 months following the last date it met the definition of an EGU subject to the Subpart (e.g., 6 months after a cogeneration unit provided more than one third of its potential electrical output capacity and more than 25 megawatts electrical output to any power distributions system for sale). The Source may opt to remain subject to the provisions of Subpart UUUUU beyond 6 months after the last date it met the definition of an EGU subject to the Subpart (40 CFR Part 63, §63.10000(f)).

5.2.7 Except as provided under §63.10000(n) (Condition 5.2.16), if the unit no longer meets the definition of an EGU subject to Subpart UUUUU the Source must be in compliance with any newly applicable standards on the date which it is no longer subject to the Subpart. The date the Source is no longer subject to the Subpart is a date selected by the source, that must be at least 6 months from the date the that unit last meet the definition of an EGU subject to the Subpart. The Source shall remain in compliance with Subpart UUUUU until the date it selected to cease complying with the Subpart (40 CFR Part 63, §63.10000(g)).

5.2.8 If the Source owns or operates an EGU that does not meet the definition of an EGU subject to Subpart UUUUU on April 16, 2015, and the Source commences or recommences operations that causes the Source to meet the definition of an EGU subject to Subpart UUUUU, the Source is subject to the provisions of Subpart UUUUU, including, but not limited to, the emission limitations and the monitoring requirements as of the first day the Source meets the definition of an EGU subject to Subpart UUUUU. The Source shall complete all initial compliance demonstrations for Subpart UUUUU applicable to the EGU within 180 days after commencing or recommencing operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU (40 CFR Part 63, §63.10000(h)(1)).

5.2.9 The Source shall provide 30 days prior notice of the date it intends to commence or recommence operations that cause the Source to meet the definition of an EGU subject to Subpart UUUUU. The notification must include the information in §63.10000(h)(2)(i) through (iv) (40 CFR Part 63, §63.10000(h)(2)).

5.2.10 If the EGU ceases to operate in a manner that causes the unit to meet the definition of an EGU subject to Subpart UUUUU, the Source must be in compliance with any newly applicable Clean Air Act (CAA) section 112 or 129 standards on the date the Source selected consistent with §63.10000(g) and (n) (Condition 5.2.7 and 5.2.16) (40 CFR Part 63, §63.10000(i)(1)).

5.2.11 The Source shall provide 30 days prior notice of the date the EGU will cease complying with Subpart UUUUU. The notification shall identify the content described in §63.10000(i)(2)(i) through (iv) (40 CFR Part 63, §63.10000(i)(2)).

5.2.12 All air pollution control equipment necessary for compliance with any newly applicable emissions limits which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart (40 CFR Part 63, §63.10000(j)).

5.2.13 All monitoring systems necessary for compliance with any newly applicable monitoring requirements which apply as a result of the cessation or commencement or recommencement of operations that cause the EGU to meet the definition of an EGU subject to Subpart UUUUU shall be installed and operational as of the date the Source ceases to be or becomes subject to the Subpart. All calibration and drift checks shall be performed as of the date the Source ceases to be or becomes subject to the Subpart. The Source shall also comply with provisions §63.10010, §63.10020, and §63.10021 of Subpart UUUUU (Conditions 5.6, 5.7, and 5.8). Relative accuracy tests shall be performed as of the performance test deadline for PM CEMS, if applicable. Relative accuracy testing for other CEMS need not be repeated if that testing was previously performed consistent with CAA section 112 monitoring requirements or monitoring requirements under Subpart UUUUU (40 CFR Part 63, §63.10000(k)).

5.2.14 On or before the date an EGU is subject to Subpart UUUUU, the Source shall install, certify, operate, maintain, and quality assure each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals during startup periods and shutdown periods. The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup periods and shutdown periods (40 CFR Part 63, §63.10000(l)).

5.2.15 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (see note in Condition 5.1.4), on or before the date the EGU is subject to Subpart UUUUU, the Source shall install, verify, operate, maintain, and quality assurance each monitoring system necessary for demonstrating compliance with the work practice standards for PM or non-mercury HAP metals controls during startup periods and shutdown periods required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10000(m)).

5.2.15.1 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications when installing, verifying, operating, maintaining, and quality assuring each monitoring system (40 CFR Part 63, §63.10000(m)(1)).

5.2.15.2 The Source shall collect, record, report, and maintain data obtained from these monitoring systems during startup and shutdown periods (40 CFR Part 63, §63.10000(m)(2)).

5.2.16 If the Source has permanently converted the EGU from coal or oil to natural gas or biomass after the compliance date (or, if applicable, after the approved extended compliance date), as demonstrated by being subject to a permit provision or physical limitation (including retirement) that prevents the Source from operating in a manner that would subject the Source to Subpart UUUUU, the Source shall no longer be subject to Subpart UUUUU, notwithstanding the coal or oil usage in the previous calendar years. The date on which the Source is no longer subject to Subpart UUUUU is the date on which the Source converted to natural gas or biomass firing; it is also the date on which the Source must be in compliance with any newly applicable standards (40 CFR Part 63, §63.10000(n)).

Units 1, 2, and 3 are equipped with flue-gas desulfurization and SO_2 monitoring systems. The source monitors compliance with the alternative SO_2 limit on a continuous basis. All units use SO_2 as a surrogate for HCl emissions. SO_2 CEMS have been certified in accordance with the applicable requirements.

Unit 1 and Unit 2 and are equipped with a CEMS to continuously monitor Hg emissions from the exhaust. Unit 3 is equipped with a Sorbent Trap Continuous Monitoring System for Hg emissions. The monitoring systems are registered in the Craig Station Monitoring Plan. Tri-State certified continuous compliance with the standard since the compliance date of the rule in their semiannual Compliance Certifications reporting no violations of an emission standard.

For each of the three Units, performance tests are conducted to demonstrate compliance with PM requirements of this subpart and as of the date of the inspection, compliance tests have been performed and approved as required. Quarterly performance testing for each of the Units have been performed for three years to demonstrate Low Emitter EGU (LEE) status for PM. The low emitter limit is 0.015 lb/MMBtu. Test results indicate that emissions have qualified all three (3) units for LEE status. Quarterly PM testing has been completed and PM testing is currently required every three years.

Source is in compliance with this condition.

5.3 §63.10006 When must I conduct subsequent performance tests or tune-ups?

5.3.1 For affected units meeting the LEE requirements of §63.10005(h), the Source must repeat the performance test once every 3 years (once every year for Hg) according to Table 5 of Subpart UUUUU and §63.10007 (Condition 5.4). Should subsequent emissions testing results show the unit does not meet the LEE eligibility requirements, LEE status is lost. If this should occur (40 CFR Part 63, §63.10006(b)):

5.3.1.1 For all pollutant emission limits except for Hg, the Source shall conduct emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(b)(1)).

5.3.1.2 For Hg, the Source shall install, certify, maintain, and operate a Hg CEMS or sorbent trap monitoring system in accordance with Appendix A to Subpart UUUUU, within 6 calendar months of losing LEE eligibility. Until the Hg CEMS or sorbent trap monitoring system is installed, certified, and operating, the Source shall conduct Hg emissions testing quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1). The Source must have 3 calendar years of testing and CEMS or sorbent trap monitoring system data that satisfy the LEE emissions criteria to reestablish LEE status (40 CFR Part 63, §63.10006(b)(2)).

5.3.2 Except where §63.10006(a) or (b) (Condition 5.3) apply, or where the Source installs, certifies, and operates a PM CEMS to demonstrate compliance with a filterable PM emissions limit, the Source shall conduct all applicable periodic emissions tests for filterable PM, individual, or total HAP metals emissions according to Table 5 of Subpart UUUUU, §63.10007, and §63.10000(c) (Conditions 5.4 and 5.2.3), except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(c)).

5.3.3 Except where §63.10006(b) (Condition 5.3) applies, for coal-fired EGUs that do not use either an HCl CEMS to monitor compliance with the HCl limit or an SO_2 CEMS to monitor compliance with the alternate equivalent SO_2 emission limit, the Source shall conduct all applicable periodic HCl emissions tests according to Table 5 of Subpart UUUUU and §63.10007 (Conditions 5.4) at least quarterly, except as otherwise provided in §63.10021(d)(1) (Condition 5.8.4.1) (40 CFR Part 63, §63.10006(d)).

5.3.4 [Time between performance tests]

5.3.4.1 Notwithstanding the provisions of §63.10021(d)(1) (Condition 5.8.4.1), the requirements listed in §63.10006 (h) (Condition 5.3.6), and the requirements of §63.10006(f)(3) (Condition 5.3.4.3), the Source shall complete performance tests for

the EGU as follows (40 CFR Part 63, §63.10006(f)(1)):

a. At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter (40 CFR Part 63, §63.10006(f)(1)(i));

b. For annual testing (40 CFR Part 63, §63.10006(f)(1)(ii)):

(i) At least 320 calendar days, measured from the test's end date, must separate performance tests (40 CFR Part 63, §63.10006(f)(1)(ii)(A));

(ii) At least 320 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 30-boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(B));

(iii) At least 230 calendar days, measured from the test's end date, must separate annual sorbent trap mercury testing for 90 boiler operating day LEE tests (40 CFR Part 63, §63.10006(f)(1)(ii)(c)); and

c. At least 1,050 calendar days, measured from the test's end date, must separate performance tests conducted every 3 years (40 CFR Part 63, §63.10006(f)(1)(iii)).

5.3.4.2 For units demonstrating compliance through quarterly emission testing, the Source must conduct a performance test in the 4th quarter of a calendar year of the EGU has skipped performance tests in the first 3 quarters of the calendar year (40 CFR Part 63, §63.10006(f)(2)).

5.3.4.3 If the EGU misses a performance test deadline due to being inoperative and if 169 or more boiler operating hours occur in the next test period, the Source must complete an additional performance test in that period as follows (40 CFR Part 63, §63.10006(f)(3)):

a. At least 15 calendar days must separate two performance tests conducted in the same quarter (40 CFR Part 63, §63.10006(f)(3)(i)).

b. At least 107 calendar days must separate two performance tests conducted in the same calendar year (40 CFR Part 63, §63.10006(f)(3)(ii)).

c. At least 350 calendar days must separate two performance tests conducted in the same 3 year period (40 CFR Part 63, §63.10006(f)(3)(iii)).

5.3.5 If the Source elects to demonstrate compliance using emissions averaging under §63.10009 (Condition 5.5), the Source must continue to conduct performance stack tests at the appropriate frequency given in §63.10006(c) through (f) (Conditions 5.3.2 through 5.3.4) (40 CFR Part 63, §63.10009(g)).

5.3.6 If a performance test on a non-mercury LEE shows emissions in excess of 50 percent of the emission limit and if the Source chooses to reapply for LEE status, the Source must conduct performance tests at the appropriate frequency given in §63.10006(c) through (e) (Conditions 5.3.2 through 5.3.3) for that pollutant until all performance tests over a consecutive 3-year period show compliance with the LEE criteria (40 CFR Part 63, §63.10006(h)).

5.3.7 The Source shall conduct a performance tune-up according to §63.10021(e) (Condition 5.8.5) (40 CFR Part 63, §63.10006(i)).

5.3.7.1 For EGUs not employing a neural network combustion optimization during normal operation, each performance tune-up specified in §63.10021(e) must be no more than 36 calendar months after the previous performance tune-up (40 CFR Part 63, §63.10006(i)(1)).

The source has performed performance tests and tune ups during the compliance period on schedule as required. The source has performed PM tests for LEE status as required by this subpart.

Source is in compliance with this condition.

5.4 §63.10007 What methods and other procedures must I use for the performance tests?

5.4.1 Except as otherwise provided in §63.10007 (Condition 5.4), the Source shall conduct all required performance tests according to §63.7(d), (e), (f), and (h). The Source must also develop a site-specific test plan according to the requirements in §63.7(c) (40 CFR Part 63, §63.10007(a)).

5.4.1.1 If a CEMS is used (for Hg, HCl, SO_2, or other) to determine compliance with a 30- (or, if applicable, 90-) boiler operating day rolling average emission limit, the Source shall collect quality-assured CEMS data for all unit operating conditions, including startup and shutdown (see §63.10011(g) and Table 3 of Subpart UUUUU), except as otherwise provided in §63.10020(b) (Condition 5.7.2). Emission rates determined during startup periods and shutdown periods (as defined in §63.10042) are not to be included in the compliance determinations, except as otherwise provided in §63.10000(c)(1)(vi)(B) and §63.10005(a)(2)(iii) (Condition 5.2.3.6.b) (40 CFR Part 63, §63.10007(a)(1)).

5.4.1.2 If the Source conducts performance testing with test methods in lieu of continuous monitoring, the Source shall operate the unit at maximum normal operating load conditions during each periodic (e.g., quarterly) performance test. Maximum normal operating load will generally be between 90 and 110 percent design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(2)).

5.4.1.3 For establishing operating limits with PM CPMS to demonstrate compliance with a PM or non-Hg metals emissions limit, the Source shall operate the unit at maximum normal operating load conditions during the performance test period. Maximum normal operating load will generally be between 90 and 110 percent of design capacity but should be representative of site-specific normal operations during each test run (40 CFR Part 63, §63.10007(a)(3)).

5.4.2 The Source shall conduct each performance test (including traditional 3-run stack tests, 30-boiler operating day tests based on CEMS data (or sorbent trap monitoring system data), and 30-boiler operating day Hg emission tests for LEE qualification) according to the requirements of Table 5 of Subpart UUUUU (40 CFR Part 63, §63.10007(b)).

5.4.3 If the Source chooses the filterable PM method to comply with the PM emission limit and demonstrates continuous compliance using a PM CPMS as provided for in §63.10000(c) (Condition 5.2.3), the Source must also establish an operating limit according to §63.10011(b), §63.10023 (Condition 5.10), and Tables 4 and 6 of Subpart UUUUU. Should the Source desire to have operating limits that correspond to loads other than maximum normal operating load, the Source must conduct testing at those other loads to determine the additional operating limits (40 CFR Part 63, §63.10007(c)).

5.4.4 Except for a 30-boiler operating day performance test based on CEMS (or sorbent trap monitoring system) data, where the concept of test runs does not apply, the Source shall conduct a minimum of three separate test runs for each performance test, as specified in §63.7(e)(3). Each test run shall comply with the minimum applicable sampling time or volume specified in Table 2 of Subpart UUUUU (Condition 5.1). Sections §63.10005(d) and (h), respectively, provide special instructions for conducting performance tests based on CEMS or

sorbent trap monitoring systems, and for conducting emission tests for LEE qualification (40 CFR Part 63, §63.10007(d)).

5.4.5 To use the results of performance testing to determine compliance with the applicable emission limits in Table 2 of Subpart UUUUU (Condition 5.1), the Source shall follow the requirements in §63.10007(e)(1) through (3) (40 CFR Part 63, §63.10007(e)).

5.4.6 If the Source elects to (or is required to) use CEMS to continuously monitor Hg, HCl, HF, SO_2, or PM emissions (or, if applicable, sorbent trap monitoring systems to continuously collect Hg emissions data), the default values are available for use in the emission rate calculations during startup periods or shutdown periods (as defined in §63.10042). Default values for diluents cap values and for default gross output are described in §63.10007(f)(1) and (2). For the purposes of Subpart UUUUU, the default values are not considered to be substitute data (40 CFR Part 63, §63.10007(f)).

5.4.7 Upon request, the Source shall make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of §63.10007 (Condition 5.4) (40 CFR Part 63, §63.10007(g))

The source has conducted performance testing and conducts monitoring consistent with the requirements above and consistent with the requirements of 40 CFR 75 when applicable as required.

Source is in compliance with this condition.

5.5 §63.10009 May I use emissions averaging to comply with this Subpart?

5.5.1 **[General eligibility]** The Source may use emissions averaging as described in §63.10009(a)(2) (Condition 5.5.2) as an alternative to meeting the requirements of §63.9991 for filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg on an EGU-specific basis if (40 CFR Part 63, §63.10009(a)(1)):

5.5.1.1 The Source has more than one existing EGU in the same subcategory located at one or more contiguous properties, belonging to a single major industrial grouping, which are under common control of the same person (or persons under common control) (40 CFR Part 63, §63.10009(a)(1)(i)); and

5.5.1.2 The Source uses CEMS (or sorbent trap monitoring systems for determining Hg emissions) or quarterly emissions testing for demonstrating compliance (40 CFR Part 63, §63.10009(a)(1)(ii)).

5.5.2 The Source may demonstrate compliance by emissions averaging among the existing EGUs in the same subcategory, if the averaged Hg emissions for EGUs in the "unit designed for coal ≥8,300 Btu/lb" subcategory are equal to or less than 1.2 lb/TBtu or 1.3E-2 lb/GWh on a 30-boiler operating day basis or if the averaged emissions of individual, other pollutants from other subcategories of such EGUs are equal to or less than the applicable emissions limit in Table 2 to this subpart, according to the procedures in this section. Note that except for the alternate Hg emissions limit from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory, the averaging time for emissions averaging for pollutants is 30-group boiler operating days (rolling daily) using data from CEMS and sorbent trap monitoring (for Hg), or a combination of data from CEMS and emissions testing (for other pollutants). The averaging time for emissions averaging for the alternate Hg limit (equal to or less than 1.0 lb/TBtu or 1.1E-2 lb/GWh) from EGUs in the "unit designed for coal ≥ 8,300 Btu/lb" subcategory is 90-group boiler operating days (rolling daily) using data from CEMS, sorbent trap monitoring, or a combination of data from CEMS and sorbent trap monitoring. For the purposes of this paragraph, 30- (or 90-) group boiler operating days is defined as a period during which at least one unit in the emissions

averaging group operates on each of the 30 or 90 days. The Source must calculate the weighted average emissions rate for the group in accordance with the procedures in this paragraph using the data from all units in the group including any that operate fewer than 30 (or 90) of the preceding 30- (or 90-) group boiler operating days (40 CFR Part 63, §63.10009(a)(2)).

5.5.2.1 The Source may choose to have the EGU emissions averaging group meet either the heat input basis (MMBtu or TBtu, as appropriate for the pollutant) or gross output basis (MWh or GWh, as appropriate for the pollutant) (40 CFR Part 63, §63.10009(a)(2)(i)).

5.5.2.2 The Source may not mix bases within the EGU emissions averaging group (40 CFR Part 63, §63.10009(a)(2)(ii)).

5.5.2.3 The Source may use emissions averaging for affected units in different subcategories if the units vent to the atmosphere through a common stack (see §63.10009(m) (Condition 5.5.14)) (40 CFR Part 63, §63.10009(a)(2)(iii)).

5.5.3 [Equations] The Source must use the following equations when performing calculations for the EGU emissions averaging group (40 CFR Part 63, §63.10009(b)):

5.5.3.1 Group eligibility equations (40 CFR Part 63, §63.10009(b)(1))

$$WAER_m = \frac{(\sum_{j=1}^{p} Herm_j * Rmm_j) + \sum_{k=1}^{m} Ter_k * Rmt_k}{(\sum_{j=1}^{p} Rmm_j) + \sum_{k=1}^{m} Rmt_k} \quad \text{Eq. 1a}$$

Where:

$WAER_m$ = Maximum Weighted Average Emission Rate in terms of lb/heat input or lb/gross output,

$Herm_{i,j}$ = Hourly emission rate (e.g., lb/MMBtu, lb/Mwh) from CEMS or sorbent trap monitoring as determined during the initial compliance determination from EGU j,

Rmm_j = Maximum rated heat input, MMBtu/h, or maximum rated gross output, MWh/h, for EGU j,

p = Number of EGUs in emissions averaging group that rely on CEMS,

Ter_k = Emissions rate (lb/MMBtu or lb/MWh) as determined during the initial compliance determination for EGU k,

Rmt_k = Maximum rated heat input, MMbtu/h, or maximum rated gross output, MWh/h, for EGU k, and

m = number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER_m = \frac{\sum[(\sum_{j=1}^{p} Herm_j) * Smm_j * Cfm_j)] + \sum_{k=1}^{m} Ter_k * Smt_k * Cft_k}{\sum(\sum_{j=1}^{p} Smm_j * Cfm_j) + \sum_{k=1}^{m} Smt_k * Cft_k} \quad \text{Eq. 1b}$$

Where:

Smm_j = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU j,

Cfm_j = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated ($MMBtu/lb_{steam}$ or MWh/lb_{steam}) from EGU j,

Smt_k = Maximum steam generation, lb_{steam}/h or lb/gross output, for EGU k, and

Cfm_k = Conversion factor, calculated from the most recent compliance test results, in terms of units of heat output or gross output per pound of steam generated (MMBtu/lb_{steam} or MWh/lb_{steam}) from EGU k.

5.5.3.2 Weighted 30-boiler operating day rolling average emissions rate equations for pollutants other than Hg. Use Equation 2a or 2b of §63.10009(b)(2) to calculate the 30 day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(2)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{p}(Her_i * Rm_i))_p + \sum_{i=1}^{m}(Ter_i * Rt_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p + \sum_{i=1}^{m} Rt_i} \quad \text{Eq. 2a}$$

Where:

Her_i = Hourly emission rate (e.g., lb/MMBtu, lb/MWh) from unit i's CEMS for the preceding 30-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 30-group boiler operating days,

p = Number of EGUs in emissions averaging group that rely on CEMS or sorbent trap monitoring,

n= Number of hours that hourly rates are collected over 30-group boiler operating days,

Ter_i = Emissions rate from most recent emissions test of unit i in terms of lb/heat input or lb/gross output,

Rt_i = Total heat input or gross output of unit i for the preceding 30-boiler operating days, and

m = Number of EGUs in emissions averaging group that rely on emissions testing.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p + \sum_{i=1}^{m}(Ter_i * St_i * Cft_i)}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p + \sum_{i=1}^{m} St_i * Cft_i} \quad \text{Eq. 2b}$$

Where:

Sm_i = Steam generation in units of pounds from unit i that uses CEMS for the preceding 30-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS from the preceding 30 group boiler operating days,

St_i = Steam generation in units of pounds from unit i that uses emissions testing, and

Cft_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit I that uses emissions testing.

5.5.3.3 Weighted 90-boiler operating day rolling average emissions rate equations for Hg emissions from EGUs in the "coal-fired unit not low rank virgin coal" subcategory.

Use equation 3a or 3b of §63.10009(b)(3) to calculate the 90-day rolling average emissions daily, as follows (40 CFR Part 63, §63.10009(b)(3)).

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Rm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Rm_i))_p} \quad \text{Eq. 3a}$$

Where:

Her_i = Hourly emission rate from unit i's CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Rm_i = Hourly heat input or gross output from unit i for the preceding 90-group boiler operating days,

p = Number of EGUs in emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

$$WAER = \frac{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Her_i * Sm_i * Cfm_i))_p}{\sum_{i=1}^{p}(\sum_{i=1}^{n}(Sm_i * Cfm_i))_p} \quad \text{Eq. 3b}$$

Where:

Her_I = Hourly emission rate from unit I's Hg CEMS or Hg sorbent trap monitoring system for the preceding 90-group boiler operating days,

Sm_i = Steam generation in units of pounds from unit i that uses CEMS or Hg sorbent trap monitoring for the preceding 90-group boiler operating days,

Cfm_i = Conversion factor, calculated from the most recent compliance test results, in units of heat input per pound of steam generated or gross output per pound of steam generated, from unit i that uses CEMS or sorbent trap monitoring from the preceding 90-group boiler operating days,

p = Number of EGUs in the emissions averaging group,

n = Number of hours that hourly rates are collected over the 90-group boiler operating days.

5.5.4 **[Separate stack requirements]** For a group of two or more existing EGUs in the same subcategory that each vent to a separate stack, the Source may average filterable PM, SO_2, HF, HCl, non-Hg HAP metals, or Hg emissions to demonstrate compliance with the limits in Table 2 to Subpart UUUUU if the Source satisfies the requirements in §63.10009(d) through (j) (Conditions 5.5.5 through 5.5.11) (40 CFR Part 63, §63.10009(c)).

5.5.5 For each existing EGU in the averaging group (40 CFR Part 63, §63.10009(d)):

5.5.5.1 The emissions rate achieved during the initial performance test for the HAP being averaged must not exceed the emissions level that was being achieved 190 days after April 16, 2015, or the date on which emissions testing done to support the emissions averaging plan is complete (if the Administrator does not require submission and approval of the emissions averaging plan), or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(1)); or

5.5.5.2 The control technology employed during the initial performance test must not be less than the design efficiency of the emissions control technology employed 180 days after April 16, 2015 or the date that the Source begins emissions averaging, whichever is earlier (40 CFR Part 63, §63.10009(d)(2)).

5.5.6 The weighted-average emissions rate from the existing EGUs participating in the emissions averaging option must be in compliance with the limits in Table 2 of Subpart UUUUU at all times following the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(e)).

5.5.7 **[Emissions averaging group eligibility demonstration]** The Source must demonstrate the ability for the EGUs included in the emissions averaging group to demonstrate initial compliance according to §63.10009(f)(1) and (2) (Conditions 5.5.7.1 and 5.5.7.2) using the maximum rated heat input or gross output over a 30- (or 90-) boiler operating day period of each EGU and the results of the initial performance tests. For this demonstration and prior to preparing the emissions averaging plan, the Source must conduct required emissions monitoring for 30- (or 90-) days of boiler operating and any required manual performance testing to calculate maximum weighted average emissions rate in accordance with §63.10009. If, before the start of the initial compliance demonstration, the Administrator becomes aware that the Source intends to use emissions averaging for that demonstration, or if the initial Notification of Compliance Status (NOCS) indicates that the Source intends to implement emissions averaging at a future date, the Administrator may require the Source to submit the proposed emissions averaging plan and supporting data for approval. If the Administrator requires approval of the plan, the Source may not being using emissions averaging until the Administrator approves the plan (40 CFR Part 63, §63.10009(f)).

5.5.7.1 The Source must use Equation 1a in §63.10009(b) (Condition 5.5.3.1) to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging option do not exceed the emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(1)).

5.5.7.2 If the Source is not capable of monitoring heat input or gross output, and the EGU generates steam for purposed other than generating electricity, the Source may use Equation 1b of §63.10009 (Condition 5.5.3.1) as an alternative to using Equation 1a of §63.10009 to demonstrate that the maximum weighted average emissions rates of filterable PM, HF, SO_2, HCl, non-Hg HAP metals, or Hg emissions from the existing units participating in the emissions averaging group do not exceed the emission limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10009(f)(2)).

5.5.8 The Source must determine the weighted average emissions rate in units of the applicable emissions limit on a 30 group boiler operating day rolling average basis (or, if applicable, on a 90 group boiler operating day rolling average basis for Hg) according to §63.10009(g)(1) and (2) (Conditions 5.5.8.1 and 5.5.8.2). The First averaging period ends on the 30th (or, if applicable, 90th for the alternate Hg emission limit) group boiler operating day after the date that the Source begins emissions averaging (40 CFR Part 63, §63.10009(g)).

5.5.8.1 The Source must use Equation 2a or 3a of §63.10009(b) (Condition 5.5.3) to calculate the weighted average emissions rate using the actual heat input or gross output for each existing unit participating in the emissions averaging option (40 CFR Part 63, §63.10009(g)(1)).

5.5.8.2 If the Source is not capable of monitoring heat input or gross output, the Source may use Equation 2b or 3b of §63.10009(b) (Condition 5.5.3) as an alternative to using Equation 2a of §63.10009(b) to calculate the average weighted emission rate using the actual steam generation from the units participating in the emissions averaging

option (40 CFR Part 63, §63.10009(g)(2)).

5.5.9 **[CEMS (or sorbent trap monitoring use)]** If an EGU in the emissions averaging group using CEMS (or sorbent trap monitoring for Hg emissions) to demonstrate compliance, the Source must use those data to determine the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(h)).

5.5.10 **[Emissions testing]** If the Source uses manual emissions testing to demonstrate compliance for one or more EGUs in the emissions averaging group, the Source must use the results from the most recent performance test to determine the 30 (or 90) day rolling average. the Source may use CEMS or sorbent trap data in combination with data from the most recent manual performance test in calculating the 30 (or 90) group boiler operating day rolling average emissions rate (40 CFR Part 63, §63.10009(i)).

5.5.11 **[Emissions averaging plan]** The Source must develop an implementation plan for emissions averaging according to the procedures and requirements in §63.10009(j)(1) and (2) (40 CFR Part 63, §63.10009(j)).

5.5.12 **[Common stack requirements]** For a group of two or more existing affected units, each of which vents through a single common stack, the Source may average emissions to demonstrate compliance with the limits in Table 2 of Subpart UUUUU if the Source satisfies the requirements of §63.10009(l) or (m) (Conditions 5.5.13 or 5.5.14) (40 CFR Part 63, §63.10009(k)).

5.5.13 For a group of two or more existing units in the same subcategory and which vent through a common emissions control system to a common stack that does not receive emissions from units in other subcategories or categories, the Source may treat such averaging group as a single existing unit for purposes of Subpart UUUUU and comply with the requirements of Subpart UUUUU as if the group were a single unit (40 CFR Part 63, §63.10009(l)).

5.5.14 For all other groups of units subject to §63.10009(k) (Condition 5.5.12), the Source may elect to conduct manual performance tests according to procedures specified in §63.10007 (Condition 5.4) in the common stack. If emissions from affected units included in the emissions averaging and from other units not included in the emissions averaging (e.g., in a different subcategory) or other nonaffected units all vent to the common stack, the Source must shut down the units not included in the emissions averaging and the nonaffected units or vent their emissions to a different stack during the performance test. Alternatively, the Source may conduct a performance test of the combined emissions in the common stack with all units operating and show that the combined emissions meet the most stringent emissions limit. The Source may also use a CEMS or sorbent trap monitoring to apply this latter alternative to demonstrate that the combined emissions comply with the most stringent emissions limit on a continuous basis (40 CFR Part 63, §63.10009(m)).

5.5.15 **[Combination requirements]** The common stack of a group of two or more existing EGUs in the same subcategory subject to §63.10009(k) (Condition 5.5.12) may be treated as a single stack for purposes of §63.10009(c) (Condition 5.5.4) and included in an emissions averaging group subject to §63.10009(c) (40 CFR Part 63, §63.10009(n)).

Tri-State does not use averaging to demonstrate compliance with applicable emissions limits.

Source is in compliance with this condition.

5.6 §63.10010 What are my monitoring, installation, operation, and maintenance requirements?

5.6.1 Flue gases from the affected units under Subpart UUUUU exhaust to the atmosphere through a variety of different configurations, including but not limited to individual stacks, a common stack configurations, or a main stack plus a bypass stack. For the CEMS, PM CPMS, and sorbent trap monitoring systems used to provide data under Subpart UUUUU, the CMS installation requirements for these exhaust configuration are described in §63.10010(a)(1) through (6) (40 CFR Part 63, §63.10010(a)).

CMS units at the facility are installed consistent with the requirements of 40 CFR Part 63, Subpart UUUUU.

Source is in compliance with this condition.

5.6.2 If an oxygen (O_2) or carbon dioxide (CO_2) CEMS is used to convert measured pollutant concentrations to the units of the applicable emissions limit, the O_2 or CO_2 concentrations shall be monitored at a location that represents emissions to the atmosphere, i.e., at the outlet of the EGU, downstream of all emission control devices. The Source shall install, certify, maintain, and operate the CEMS according to 40 CFR Part 75. Only QA O_2 or CO_2 data in the emissions calculations shall be used; Part 75 substitute data values shall not be used (40 CFR Part 63, §63.10010(b)).

CO2 diluent CEMS are installed on each of the Units at the facility. The CO2 CEMS are operated and maintained consistent with the requirements of 40 CFR Part 75 as required.

Source is in compliance with this condition.

5.6.3 If the Source is required to use a stack gas flow rate monitor, either for routine operation of a sorbent trap monitoring system or to convert pollutant concentrations to units of an electrical output-based emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain the monitoring system and conduct on-going QA testing of the system according to 40 CFR Part 75. The Source shall only use unadjusted, QA flow rate data in the emissions calculations. The Source shall not apply bias adjustment factors to the flow rate data and shall not use substitute flow rate data in the calculations (40 CFR Part 63, §63.10010(c)).

Each of the Units at the facility is equipped with a stack flow monitor. The stack flow monitors are operated and maintained consistent with the requirements of 40 CFR Part 75 as required.

Source is in compliance with this condition.

5.6.4 If the Source is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 2 of Subpart UUUUU, the Source shall install, certify, operate, and maintain a moisture monitoring system in accordance with 40 CFR Part 75. Alternatively, for coal-fired units, the Source may use appropriate fuel-specific default moisture values from 40 CFR Part 75, §75.11(b) to estimate the moisture content of the stack gas. If the Source installs and operates a moisture monitoring system, the Source shall not use substitute moisture data in the emissions calculations (40 CFR Part 63, §63.10010(d)).

Tri-State utilizes the moisture default values from 40 CFR Part 75 to estimate stack moisture.

Source is in compliance with this condition.

5.6.5 If the Source uses an HCl and/or HF CEMS, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix B of Subpart UUUUU. The Source shall calculate and record a 30-boiler operating day rolling average HCl

or HF emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all the valid hourly HCl or HF emission rates in the preceding 30 boiler operating days (see section 9.4 of Appendix B to Subpart UUUUU) (40 CFR Part 63, §63.10010(e)).

Tri-State does not operate HCl or HF CEMS at the facility.

Source is in compliance with this condition.

5.6.6 If the Source uses an SO_2 CEMS:

5.6.6.1 The Source shall install the monitor at the outlet of the EGU, downstream of all emission control devices, and the Source shall certify, operated, and maintain the CEMS according to 40 CFR Part 75 (40 CFR Part 63, §63.10010(f)(1)).

5.6.6.2 For on-going QA, the SO_2 CEMS shall meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of Appendix B to 40 CFR Part 75, with the following addition: the Source shall perform the linearity checks required in section 2.2 of Appendix B of 40 CFR Part 75 if the SO_2 CEMS has a span value of 30 ppm or less (40 CFR Part 63, §63.10010(f)(2)).

5.6.6.3 The Source shall calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid hourly SO_2 emission rates in the 30-boiler operating day period (40 CFR Part 63, §63.10010(f)(3)).

5.6.6.4 The Source shall use only unadjusted, QA SO_2 concentration values in the emission calculations; the Source shall not apply bias adjustment factors to the Part 75 O_2 data and shall not use Part 75 substitute data values. For startup or shutdown hours (as defined in §63.10042) the default gross output and the diluents cap are available for use in the hourly SO_2 emission rate calculations, as described in §63.10007(f) (Condition 5.4.6). The Source shall use a flag to identify each startup or shutdown hour and report a special code if the diluents cap or default gross output is used to calculate the SO_2 emission rate for any of these hours (40 CFR Part 63, §63.10010(f)(4)).

An SO_2 monitoring system is installed on the equipment at the facility as required. The source reported performing activities required by 40 CFR 75 Appendix B 2.1—2.3 (e.g. daily assessments, linearity checks) as required. The source calculates rolling emissions as required and only used unadjusted, quality-assured SO_2 concentration (ppm) values, which passed the annual RATAs on June 10, 2024 for Unit 1, June 11, 2024 for Unit 2 and June 14, 2024 for Unit 3. A bias adjustment factor was not used for any of the units.

Source is in compliance with this condition.

5.6.7 If the Source uses and Hg CEMS or a sorbent trap monitoring system, the Source shall install, certify, operate, maintain, and QA the data from the monitoring system in accordance with Appendix A of Subpart UUUUU. The Source shall calculate and record a 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average Hg emission rate, in units of the standard, updated after each new boiler operating day. Each 30- (or, if alternate emissions averaging is used, 90-) boiler operating day rolling average emission rate, calculated according to Section 6.2 of Appendix A of Subpart UUUUU, is the average of all the valid hourly Hg emission rates in the preceding 30- (or, if alternate emissions averaging is used, a 90-) boiler operating days. Section 7.1.4.3 of Appendix A of Subpart UUUUU explains how to reduce sorbent trap monitoring system data to an hourly basis (40 CFR Part 63, §63.10010(g)).

Unit 1 and Unit 2 are equipped with certified CEMS to continuously monitor Mercury emissions. The Mercury CEMS are operated and maintained consistent with the requirements of 40 CFR 63, Subpart UUUUU Appendix A requirements. Passing RATAs were conducted on the Mercury monitor installed on Unit 1 on June 14, 2024 and on Unit 2 on June 11, 2024. Unit 3 is equipped with a certified Mercury Sorbent Trap Monitoring System. The Mercury Sorbent Trap Monitoring System is operated and maintained consistent with the requirements of 40 CFR 63, Subpart UUUUU Appendix A requirements. A passing RATA was conducted on the Mercury Sorbent Trap Monitoring System installed on Unit 3 on June 14, 2024.

Source is in compliance with this condition.

5.6.8 If the Source uses a PM CPMS to demonstrate continuous compliance with an operating limit, the Source shall install, calibrate, maintain, and operate the PM CPMS and record the output of the system as specified in §63.10010(h)(1) through (7) (40 CFR Part 63, §63.10010(h)).

5.6.9 If the Source chooses to comply with the PM filterable emission limit in lieu of metal HAP limits, the Source may choose to install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in §63.10010(i)(1) through (5). The compliance limit will be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10010(i)).

5.6.10 The Source may choose to comply with the metal HAP emissions limits using CEMS approved in accordance with §63.7(f) as an alternative to the performance test method specified in Subpart UUUUU. If approved to use a HAP metals CEMS, the compliance limit shall be expressed as a 30-boiler operating day rolling average of the numerical emissions limit value applicable for the unit in Table 2 of Subpart UUUUU. If approved, the Source may choose to install, certify, operated, and maintain a HAP metals CEMS and record the output of the HAP metals CEMS as specified in §63.10010(j)(1) through (5) (40 CFR Part 63, §63.10010(j)).

5.6.11 If the Source chooses to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source must install, verify, operate, maintain, and QA each monitoring system necessary for demonstrating compliance with the PM or non-mercury metals work practice standards required to comply with §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10010(l)).

5.6.11.1 The Source shall develop a site-specific monitoring plan for PM or non-mercury metals work practice monitoring during startup periods (40 CFR Part 63, §63.10010(l)(1)).

5.6.11.2 The Source shall submit the site-specific monitoring plan upon request by the Administrator (40 CFR Part 63, §63.10010(l)(2)).

5.6.11.3 The provisions of the monitoring plan must address the items in §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(3)).

5.6.11.4 The Source may rely on monitoring system specifications or instructions or manufacturer's specifications to address §63.10010(l)(3)(i) through (vi) (40 CFR Part 63, §63.10010(l)(4)).

5.6.11.5 The Source shall operate and maintain the monitoring system according to the site-specific monitoring plan (40 CFR Part 63, §63.10010(l)(5)).

Tri-State does no operate a PM CPMS at the facility.

Source is in compliance with this condition.

5.7 §63.10020 How do I monitor and collect data to demonstrate continuous compliance?

5.7.1 The Source must monitor and collect data according to §63.10020 and the site-specific monitoring plan required by §63.10000(d) (Condition 5.2.4) (40 CFR Part 63, §63.10020(a)).

5.7.2 The Source must operate the monitoring system and collect data at all required intervals at all times that the affected EGU is operating, except for required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments, and any scheduled maintenance as defined in the site-specific monitoring plan. The Source is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable (40 CFR Part 63, §63.10020(b)).

5.7.3 The Source may not use data recorded during EGU startup or shutdown in calculations used to report emissions, except as otherwise provided in §63.10000(c)(1)(vi)(B) (Condition 5.2.3.6b) and §63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, or required monitoring system QA or QC activities may not be used in calculations used to report emissions or operating levels. The Source shall use all of the QA data collected during all other periods in assessing the operation of the control device and associated control system (40 CFR Part 63, §63.10020(c)).

5.7.4 Periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods, and required monitoring system quality assurance or quality control activities excluding zero and span checks must be reported as time the monitor was inoperative (downtime) under 63.10(c). Failure to collect required quality-assured data during monitoring system malfunctions, monitoring system out-of-control periods, or repairs associated with monitoring system malfunctions or monitoring system out-of-control periods is a deviation from the monitoring requirements (40 CFR Part 63, §63.10020(d)).

5.7.5 If the Source elects to reply on paragraph (2) of the definition of "startup" in §63.10042 for the EGU (40 CFR Part 63, §63.10020(e)):

5.7.5.1 During each period of startup, the Source shall record the information in §63.10020(e)(1)(i) through (v) (40 CFR Part 63, §63.10020(e)(1)).

5.7.5.2 During each period of shutdown, the Source shall record the information in §63.10020(e)(2)(i) through (v) (40 CFR Part 63, §63.10020(e)(2)).

5.7.5.3 For PM or non-mercury HAP metals work practice monitoring during startup periods, the Source shall monitor and collect data according to §63.10020(e)(3)(i)(A) through (E) and the site-specific monitoring plan required by §63.10010(l) (Condition 5.6.11) (40 CFR Part 63, §63.10020(e)(3)).

Monitoring and data collection are conducted consistent with the above requirements. Deviations are reported as required.

Tri-State reported 13.9% downtime for the mercury sorbent trap monitoring system on Unit 3 for the second quarter of 2024 and 9.19% downtime for the mercury sorbent trap monitoring system on Unit 3 for the third quarter of 2024.

Tri-State reported that during the second quarter of 2024 one set of traps failed to meet the QA/QC requirements as a result of the operator leaving the sample valves open amounting to 4.4% of the reported 13.9% downtime. Tri-State has initiated a procedure requiring the operator to photograph the sample

valves and send a photograph of the position of the sample valves to the Environmental Manager showing that valve are closed with each trap replacement to prevent a reoccurrence.

An additional 7.0% of the second quarter 2024 downtime was attributed to bad baseline calculations and failing to meet the stack gas flow rate to sample flow rate requirement of EPA Performance Specification 12B as a result of low operating load during startup, with unit load under 150 MW. Tri-State has implemented a new plan to monitor startups a on a separate set of traps to reduce downtime while also reducing the risk of bad baseline calculations on the sample run. If a baseline must be measured while the unit is in startup, the sample will be run until the unit reached 150 MW and then switch to a new sample to be run normally.

Tri-State reported that 9% of the third quarter downtime resulted from a configuration error in one of the mercury consoles after it was returned from maintenance at the manufacturer. The mercury consoles are intended to collect baseline data in a proportional flow based on a target ratio in order to meet the minimum sample mass requirement of EPA Performance Specification 12B. In this instance, the console was configured to sample at a fixed rate during the first hour of sampling and then reverted to proportional flow. The fixed sample rate ration did not match the proportional sample rate ratio, and did not meet the requirements of EPA Performance Specification 12B. The console configuration has been updated and baselines are now collected during an appropriate baseline period with proportional flow based on a target ratio.

Tri-State reported mercury emissions of 2.32 pound for the second quarter 2024 and 1.14 pounds for the third quarter of 2024. The Unit 3 mercury monitor downtime for the second and third quarters of 2024 is not considered to be excessive.

Source is in compliance with this condition.

5.8 §63.10021 How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?

5.8.1 The Source shall demonstrate continuous compliance with each emissions limit, operating limit, and work practice standard in Tables 2 through 4 of Subpart UUUUU, according to the monitoring specified in Tables 6 and 7 of Subpart UUUUU and §63.10021(b) through (g) (40 CFR Part 63, §63.10021(a)).

5.8.2 Except as otherwise provided in §63.10020(c) (Condition 5.7.3), if the Source chooses to use a CEMS to measure SO_2, PM, HCl, HF, or Hg, emissions, or using a sorbent trap monitoring system to measure Hg emissions, the Source must demonstrate continuous compliance by using all QA hourly data recorded by the CEMS (or sorbent trap monitoring system) and the other required monitoring systems (e.g., flow rate, CO_2, O_2, or moisture systems) to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 8 of Subpart UUUUU (below) to determine the 30- (or, if applicable, 90-) boiler operating day rolling average (40 CFR Part 63, §63.10021(b)).

$$Boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Her_i}{n} \quad \text{Eq. 8}$$

Where: Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30- (or, if applicable, 90-) boiler operating days.

5.8.3 If the Source uses PM CPMS data to measure compliance with an operating limit in Table 4 of Subpart UUUUU, the Source must record the PM CPMS output data for all periods when the

process is operating and the PM CPMS is not out-of-control. The Source shall demonstrate continuous compliance by using all QA hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (e.g., milliamps, PM concentration, raw data signal) on a 30-operating day rolling average basis, updated at the end of each new boiler operating day. The Source shall use Equation 9 of Subpart UUUUU (below) to determine the 30-boiler operating day average (40 CFR Part 63, §63.10021(c)).

$$30\ boiler\ operating\ day\ average = \frac{\sum_{i=1}^{n} Hpv_i}{n} \qquad \text{Eq. 9}$$

Where: Hpv_i is the hourly parameter value for hour i and n is the number of valid hourly parameter values collected over 30-boiler operating days.

5.8.4 If the Source uses quarterly performance testing to demonstrate compliance with one or more applicable emissions limits in Table 2 of Subpart UUUUU (40 CFR Part 63, §63.10021(d)), the Source

5.8.4.1 May skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year (40 CFR Part 63, §63.10021(d)(1)).

5.8.4.2 Must conduct the performance test as defined in Table 5 of Subpart UUUUU and calculate the results of the testing in units of the applicable emissions standard (40 CFR Part 63, §63.10021(d)(2)); and

5.8.5 The Source shall conduct periodic performance tune-ups of the EGU, as specified in §63.10021(e)(1) through (9). For the first tune-up, the Source may perform the burner inspection any time prior to the tune-up or may delay the first burner inspection until the next schedule EGU outage provided the Source meets the requirements of §63.10005. Subsequently, the Source shall perform an inspection of the burner at least once every 48 calendar months. If the EGU is offline when a deadline to perform the tune-up passes, the Source shall perform the tune-up work practice requirements within 30 days after the re-start of the affected unit (40 CFR Part 63, §63.10021(e)).

5.8.6 The Source must submit the applicable reports and notifications required under 40 CFR 63.10031(a) through (k) (Condition 5.12) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool. If the final date of any time period (or any deadline) for any of these submissions falls on a weekend or a Federal holiday, the time period shall be extended to the next business day. Moreover, if the EPA Host System supporting the ECMPS Client Tool is offline and unavailable for submission of reports for any part of a day when a report would otherwise be due, the deadline for reporting is automatically extended until the first business day on which the system becomes available following the outage. Use of the ECMPS Client Tool to submit a report or notification required under this subpart satisfies any requirement under subpart A of this part to submit that same report or notification (or the information contained in it) to the appropriate EPA Regional office or state agency whose delegation request has been approved (40 CFR Part 63, §63.10021(f)).

5.8.7 The Source shall report each instance in which it did not meet an applicable emissions limit or operating limit in Tables 2 through 4 of Subpart UUUUU or failed to conduct a required tune-up. These instances are deviations from the requirements of Subpart UUUUU. These deviations shall be reported according to §63.10031 (Condition 5.12) (40 CFR Part 63, §63.10021(g)).

5.8.8 The Source shall follow the startup or shutdown requirements as given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10021(h)).

5.8.8.1 The Source may use the diluents cap and default gross output values, as described in §63.10007(f) (Condition 5.4.6), during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(1)).

5.8.8.2 The Source shall operate all CMS, collect data, calculate pollutant emission rates, and record data during startup periods or shutdown periods (40 CFR Part 63, §63.10021(h)(2)).

5.8.8.3 The Source may choose to submit an alternative non-opacity emission standard, in accordance with the requirements contained in §63.10011(g)(4). Until promulgation in the Federal Register of the final alternative non-opacity emission standard, the Source shall comply with paragraph (1) of the definition of "startup" in §63.10042 (40 CFR Part 63, §63.10021(h)(4)).

5.8.9 If you are on paragraph 2 of the definition of startup in 40 CFR 63.10042, the Source must provide reports concerning activities and periods of startup and shutdown that occur on or prior to January 1, 2024, in accordance with 40 CFR 63.10031(c)(5), in the semiannual compliance report. For startup and shutdown incidents that occur on and after January 1, 2024, the Source must provide the applicable information referenced in 40 CFR 63.10031(c)(5)(ii) and 40 CFR 63.10020(e) quarterly, in PDF files, in accordance with 40 CFR 63.10031(i) (40 CFR Part 63, §63.10021(i)).

Performance tune-ups of the units are conducted and recorded as required. The source operates Continuous Monitoring System equipment at all times. Records and monitoring data are maintained as required. All monitoring systems and control systems are maintained and operated as required. The source certifies compliance in semi-annual reports.

Source is in compliance with this condition.

5.9 §63.10022 How do I demonstrate continuous compliance under the emissions averaging provision?

5.9.1 Following the compliance date, the Source must demonstrate compliance with Subpart UUUUU on a continuous basis by meeting the requirements of §63.10022(a)(1) through (4), as follows (40 CFR Part 63, §63.10022(a)).

5.9.1.1 For each 30- (or 90-) day rolling average period, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in §63.10009(f) and (g) (Conditions 5.5.7and 5.5.8) (40 CFR Part 63, §63.10022(a)(1));

5.9.1.2 For each existing unit participating in the emissions averaging option that is equipped with PM CPMS, maintain the average parameter value at or below the operating limit established during the most recent performance test (40 CFR Part 63, §63.10022(a)(2));

5.9.1.3 For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 of Subpart UUUUU that applies (40 CFR Part 63, §63.10022(a)(3)).

5.9.1.4 For each existing EGU participating in the emissions averaging option, operate in accordance with the startup or shutdown work practice requirements given in Table 3 of Subpart UUUUU (40 CFR Part 63, §63.10022(a)(4)).

5.9.2 Any instance where the Source fails to comply with the continuous monitoring requirements in §63.10022(a)(1) through (3) (Conditions 5.9.1.1 through 5.9.1.3) is a deviation (40 CFR Part 63, §63.10022(b)).

Tri-State does not utilize the emissions averaging option.

Source is in compliance with this condition.

5.10 §63.10023 How do I establish my PM CPMS operating limit and determine compliance with it?

5.10.1 During the initial performance test or any such subsequent performance test that demonstrates compliance with filterable PM, individual non-mercury HAP metals, or total non-mercury HAP metals limit (or for liquid oil-fired units, individual HAP metals or total HAP metals limit, including Hg) in Table 2, the Source shall record all hourly average output values (e.g., milliamps, stack concentration, or other raw data signal) from the PM CPMS for the periods corresponding to the test runs (e.g., nine 1-hour average PM CPMS output values for three 3-hour test runs) (40 CFR Part 63, §63.10023(a)).

5.10.2 The Source shall determine the operating limit as provided in §63.10023(b)(1) and (2). The Source shall verify an existing or establish a new operating limit after each repeated performance test (40 CFR Part 63, §63.10023(b)).

5.10.2.1 The Source shall determine the operating limit according to the requirements of §63.10023(b)(i) through (vi)) (40 CFR Part 63, §63.10023(b)(2)).

5.10.3 The Source shall operate and maintain the process and equipment such that the 30 operating day average PM CMPS output does not exceed the operating limit determined in §63.10023(a) and (b) (40 CFR Part 63, §63.10023(c)).

Tri-State does not operate a PM CPMS at the facility.

Source is in compliance with this condition.

5.11 §63.10030 What notifications must I submit and when?

5.11.1 The Source shall submit all of the notifications in §63.7(b) and (c), §63.8(e), (f)(4) and (6), and §63.9(b) through (h) that apply by the dates specified (40 CFR Part 63, §63.10030(a)).

5.11.2 As specified in §63.9(b)(2), if the Source commences startup on an affected EGU before April 16, 2012, the Source shall submit an Initial Notification not later than 120 days after April 16, 2012 (40 CFR Part 63, §63.10030(b)).

5.11.3 When the Source is required to conduct a performance test, the Source shall submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin (40 CFR Part 63, §63.10030(d)).

5.11.4 When the Source is required to conduct an initial compliance demonstration as specified in §63.10011(a), the Source shall submit a Notification of Compliance Status according to §63.9(h)(2)(ii). The Notification of Compliance Status report shall contain all the information specified in §63.10030(e)(1) through (8), as applicable (40 CFR Part 63, §63.10030(e)).

5.11.5 The Source shall submit the notifications in §63.10000(h)(2) and (i)(2) (Conditions 5.2.8 and 5.2.10) that may apply by the dates specified (40 CFR Part 63, §63.10030(f)).

The source has submitted the required notifications.

Source is in compliance with this condition.

5.12 §63.10031 What reports must I submit and when?

5.12.1 The source must submit each report in §63.10031(a)(1) through (5) that applies (40 CFR Part 63, §63.10031(a)).

5.12.2 The source must submit semiannual compliance reports according to the requirements in §63.10031(b)(1) through (6) (40 CFR Part 63, §63.10031(b)).

5.12.3 The compliance report shall contain the information required in §63.10031(c)(1) through (10) (40 CFR Part 63, §63.10031(c)).

5.12.4 Excess emissions and deviation reporting. For EGUs whose owners or operators rely on a CMS to comply with an emissions or operating limit, the semiannual compliance reports described in §63.10031(c) (Condition 5.12.3) must include the excess emissions and monitor downtime summary report described in 40 CFR §63.10(e)(3)(vi). However, starting with the first calendar quarter of 2024, reporting of the information under 40 CFR §63.10(e)(3)(vi) (and under paragraph (e)(3)(v), if the applicable excess emissions and/or monitor downtime threshold is exceeded) is discontinued for all CMS, and the Source must, instead, include in the quarterly compliance reports described in paragraph §63.10031(g) (Condition 5.12.7) the applicable data elements in section 13 of Appendix E of Subpart UUUUU for any "deviation" (as defined in 40 CFR §63.10042 and elsewhere in Subpart UUUUU) that occurred during the calendar quarter. If there were no deviations, the Source must include a statement to that effect in the quarterly compliance report (40 CFR Part 63, §63.10031(d)).

5.12.5 Each affected source that has obtained a Title V Operating Permit pursuant to 40 CFR Part 70 or Part 71 must report all deviations as defined in Subpart UUUUU in the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A). If an affected source submits a semiannual compliance report pursuant to §63.10031(c) and (d) (Condition 5.12.3 and 5.12.4), or two quarterly compliance reports covering the appropriate calendar half pursuant to §63.10031(g) (Condition 5.12.7), along with, or as part of, the semiannual monitoring report required by 40 CFR §70.6(a)(3)(iii)(A) or 40 CFR §71.6(a)(3)(iii)(A), and the compliance report(s) includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in Subpart UUUUU, submission of the compliance report(s) satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of the compliance report(s) does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority (40 CFR Part 63, §63.10031(e)).

5.12.6 For each performance stack test completed prior to January 1, 2024, (including 30- (or 90-) boiler operating day Hg LEE demonstration tests and PM tests to establish operating limits for PM CPMS), the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR §63.10031(g) (Condition 5.12.7), the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU along with the quarterly compliance report for the calendar quarter in which the test was completed (40 CFR Part 63, §63.10031(f)).

5.12.6.1 For each RATA of an Hg, HCl, HF, or SO_2 monitoring system completed prior to January 1, 2024, and for each PM CEMS correlation test, each relative response audit (RRA) and each response correlation audit (RCA) of a PM CEMS completed prior to that date, the Source must submit a PDF test report in accordance with §63.10031(f)(6) (Condition 5.12.6.5), no later than 60 days after the date on which the test is completed. For each SO_2 or Hg RATA completed on or after January 1, 2024, the Source must submit the applicable reference method information in sections 17 through 31 of Appendix E of Subpart UUUUU prior to or concurrent with the relevant quarterly emissions report. For HCl or HF RATAs, and for

correlation tests, RRAs, and RCAs of PM CEMS that are completed on or after January 1, 2024, the Source must submit the appendix E reference method information together with the summarized electronic test results, in accordance with section 11.4 of Appendix B of Subpart UUUUU or section 7.2.4 of Appendix C of Subpart UUUUU, as applicable (40 CFR Part 63, §63.10031(f)(1)).

5.12.6.2 If, for a particular EGU or a group of EGUs serving a common stack, the Source has elected to demonstrate compliance using a PM CEMS, an approved HAP metals CEMS, or a PM CPMS, the Source must submit quarterly PDF reports in accordance with §63.10031(f)(6) (Condition 5.12.6.5), which include all of the 30-boiler operating day rolling average emission rates derived from the CEMS data or the 30-boiler operating day rolling average responses derived from the PM CPMS data (as applicable). The quarterly reports are due within 60 days after the reporting periods ending on March 31st, June 30th, September 30th, and December 31st. Submission of these quarterly reports in PDF files shall end with the report that covers the fourth calendar quarter of 2023. Beginning with the first calendar quarter of 2024, the compliance averages shall no longer be reported separately, but shall be incorporated into the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7). In addition to the compliance averages for PM CEMS, PM CPMS, and/or HAP metals CEMS, the quarterly compliance reports described in §63.10031(g) (Condition 5.12.7) must also include the 30- (or, if applicable 90-) boiler operating day rolling average emission rates for Hg, HCl, HF, and/or SO_2, if the Source has elected to (or are required to) continuously monitor these pollutants. Further, if the EGU or common stack is in an averaging plan, the quarterly compliance reports must identify all of the EGUs or common stacks in the plan and must include all of the 30- (or 90-) group boiler operating day rolling weighted average emission rates (WAERs) for the averaging group (40 CFR Part 63, §63.10031(f)(2)).

5.12.6.3 The Source must submit semiannual compliance reports as required under §63.10031(b) through (d) (Conditions 5.12.2 through 5.12.4), ending with a report covering the semiannual period from July 1 through December 31, 2023, and Notifications of Compliance Status as required under §63.10030(e) (Condition 5.12.5), as PDF files. Quarterly compliance reports shall be submitted in XML format thereafter, in accordance with §63.10031(g) (Condition 5.12.7), starting with a report covering the first calendar quarter of 2024 (40 CFR Part 63, §63.10031(f)(4)).

5.12.6.4 All reports required by Subpart UUUUU not subject to the requirements in §63.10031(f) and (f)(1) through (4) (Conditions 5.12.6 through 5.12.6.3) shall be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the Source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to §63.10031(f) and (f)(1) through (4) in paper format (40 CFR Part 63, §63.10031(f)(5)).

5.12.6.5 All reports and notifications described in §63.10031(f) introductory text, (f)(1), (2), and (4) shall be submitted to the EPA in the specified format and at the specified frequency, using the ECMPS Client Tool. Each PDF version of a stack test report, CEMS RATA report, PM CEMS correlation test report, RRA report, and RCA report must include sufficient information to assess compliance and to demonstrate that the reference method testing was done properly. Note that EPA will continue to accept, as necessary, PDF reports that are being phased out at the end of 2023, if the submission deadlines for those reports extend beyond December 31, 2023. The data elements in §63.10031(f)(6)(i) through (xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file (40 CFR Part 63, §63.10031(f)(6)).

5.12.7 Starting with a report for the first calendar quarter of 2024, the Source must use the ECMPS Client Tool to submit quarterly electronic compliance reports. Each quarterly compliance report shall include the applicable data elements in sections 2 through 13 of Appendix E to Subpart UUUUU. For each stack test summarized in the compliance report, the Source must also submit the applicable reference method information in sections 17 through 31 of Appendix E to Subpart UUUUU. The compliance reports and associated appendix E information must be submitted no later than 60 days after the end of each calendar quarter. (40 CFR Part 63, §63.10031(g)).

5.12.8 On and after January 1, 2024, initial Notifications of Compliance Status (if any) shall be submitted in accordance with 40 CFR §63.9(h)(2)(ii), as PDF files, using the ECMPS Client Tool. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each Notification (40 CFR Part 63, §63.10031(h)).

5.12.9 If the Source has have elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown incidents that occur on or prior to December 31, 2023, the Source must include the information in 40 CFR §63.10031(c)(5) in the semiannual compliance report, in a PDF file. If the Source has elected to use paragraph (2) of the definition of "startup" in 40 CFR §63.10042, then, for startup and shutdown event(s) that occur on or after January 1, 2024, the Source must use the ECMPS Client Tool to submit the information in 40 CFR §63.10031(c)(5) and 40 CFR §63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024. The applicable data elements in §63.10031(f)(6)(i) through (xii) (Condition 5.12.6.5) must be entered into ECMPS with each startup and shutdown report (40 CFR Part 63, §63.10031(i)).

5.12.10 If the Source elects to use a certified PM CEMS to monitor PM emissions continuously to demonstrate compliance with Subpart UUUUU and have begun recording valid data from the PM CEMS prior to November 9, 2020, the Source must use the ECMPS Client Tool to submit a detailed report of the PS 11 correlation test (see Appendix B to 40 CFR Part 63) in a PDF file no later than 60 days after that date. For a correlation test completed on or after November 9, 2020, but prior to January 1, 2024, the Source must submit the PDF report no later than 60 days after the date on which the test is completed. For a correlation test completed on or after January 1, 2024, the Source must submit the PDF report according to section 7.2.4 of Appendix C to Subpart UUUUU. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(j)).

5.12.11 If the Source elects to demonstrate compliance using a PM CPMS or an approved HAP metals CEMS, the Source must submit quarterly reports of the QA/QC activities (*e.g.,* calibration checks, performance audits), in a PDF file, beginning with a report for the first quarter of 2024, if the PM CPMS or HAP metals CEMS is used for the compliance demonstration in that quarter. Otherwise, the Source must submit a report for the first calendar quarter in which the PM CPMS or HAP metals CEMS is used to demonstrate compliance. These reports are due no later than 60 days after the end of each calendar quarter. The applicable data elements in §63.10031(f)(6)(i) through (xii) must be entered into ECMPS with the PDF report (40 CFR Part 63, §63.10031(k)).

The source certifies compliance in Semi-Annual Monitoring and Deviation reports and Annual Compliance Certifications as required. Reports are also submitted to CEDRI as required.

Source is in compliance with this condition.

5.13 §63.10032 What records must I keep?

5.13.1 The Source must keep records according to §63.10032(a)(1) and (2). If the Source is required to (or elects to) continuously monitor Hg and/or HCl and/or HF and/or PM emissions, or if the Source elects to use a PM CPMS, the Source must keep the records required under Appendix A and/or Appendix B and/or Appendix C and/or Appendix D to Subpart UUUUU. If the Source elects to conduct periodic (*e.g.,* quarterly or annual) performance stack tests, then, for each test completed on or after January 1, 2024, the source must keep records of the applicable data elements under 40 CFR §63.7(g). The Source must also keep records of all data elements and other information in Appendix E to Subpart UUUUU that apply to the compliance strategy (40 CFR Part 63, §63.10032(a)).

5.13.1.1 In accordance with 40 CFR §63.10(b)(2)(xiv), a copy of each notification or report that the Source submits to comply with this Subpart UUUUU. The Source must also keep records of all supporting documentation for the initial Notifications of Compliance Status, semiannual compliance reports, or quarterly compliance reports that you submit (40 CFR Part 63, §63.10032(a)(1)).

5.13.1.2 Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in §63.10(b)(2)(viii) (40 CFR Part 63, §63.10032(a)(2)).

5.13.2 For each CEMS and CPMS, the Source shall keep records according to §63.10032(b)(1) through (4) (40 CFR Part 63, §63.10032(b)).

5.13.2.1 Records as described in §63.10(b)(2)(vi) through (xi) (40 CFR Part 63, §63.10032(b)(1)).

5.13.2.2 Previous (i.e., superseded) versions of the performance evaluation plan as required in §63.8(d)(3) (40 CFR Part 63, §63.10032(b)(2)).

5.13.2.3 Request for alternatives to relative accuracy test for CEMS as required in §63.8(f)(6)(i) (40 CFR Part 63, §63.10032(b)(3)).

5.13.2.4 Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period (40 CFR Part 63, §63.10032(b)(4)).

5.13.3 The Source shall keep the records required in Table 7 of Subpart UUUUU including records of all monitoring data and calculated averages for applicable PM CPMS operating limits to show continuous compliance with each emission limit and operating limit, as applicable (40 CFR Part 63, §63.10032(c)).

5.13.4 The Source shall also keep the records in §63.10032(d)(1) through (3) (Conditions 5.13.4.1 through 5.13.4.3) (40 CFR Part 63, §63.10032(d)).

5.13.4.1 The Source shall keep records of monthly fuel use by each EGU, including the type(s) of fuel and amount(s) used (40 CFR Part 63, §63.10032(d)(1)).

5.13.4.2 If the Source combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR §241.3(b)(1), the Source shall keep a record which documents how the secondary material meets each of the legitimacy criteria. If the Source combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR §241.3(b)(2), the Source shall keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR §241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under §40 CFR §241.3(c), the Source shall keep a record which documents how the fuel satisfies the requirements of the petition process (40 CFR Part 63, §63.10032(d)(2)).

5.13.4.3 For an EGU that qualifies as a LEE under §63.10005(h), the Source shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions for the pollutant to increase within the last year (40 CFR Part 63, §63.10032(d)(3)).

5.13.5 If the Source elects to average emissions consistent with §63.10009 (Condition 5.5), the Source must additionally keep a copy of the emissions averaging implementation plan required in §63.10009(g), all calculations required under §63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with §63.10022 (Condition 5.9) (40 CFR Part 63, §63.10032(e)).

5.13.6 Regarding startup or shutdown periods (40 CFR Part 63, §63.10032(f)):

5.13.6.1 Should the Source choose to rely on paragraph (1) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of the occurrence and duration of each startup or shutdown (40 CFR Part 63, §63.10032(f)(1)).

5.13.6.2 Should the Source choose to rely on paragraph (2) of the definition of "startup" in §63.10042 for the EGU, the Source shall keep records of (40 CFR Part 63, §63.10032(f)(2)):

a. The determination of the maximum possible clean fuel capacity for the EGU (40 CFR Part 63, §63.10032(f)(2)(i));

b. The determination of the maximum possible hourly clean fuel heat input and of the hourly clean fuel heat input for each EGU (40 CFR Part 63, §63.10032(f)(2)(ii));

c. The information required in §63.10020(e) (Condition 5.7.5) (40 CFR Part 63, §63.10032(f)(2)(iii)).

5.13.7 The source shall keep records of the occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment (40 CFR Part 63, §63.10032(g)).

5.13.8 The Source shall keep records of actions taken during periods of malfunction to minimize emissions in accordance with §63.10000(b) (Condition 5.2.2), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation (40 CFR Part 63, §63.10032(h)).

5.13.9 The Source shall keep records of the type(s) and amount(s) of fuel used during each startup or shutdown (40 CFR Part 63, §63.10032(i)).

5.13.10 If the Source elects to establish that an EGU qualifies as a limited-use liquid oil-fired EGU, the Source shall keep records of the type(s) and amounts(s) of fuel use in each calendar quarter to document that the capacity factor limitation for that subcategory is met (40 CFR Part 63, §63.10032(j)).

Records required by this section for the continuous monitoring of Hg are maintained by the source as required. All other records as required above are maintained.

Source is in compliance with this condition.

5.14 §63.10033 In what form and how long must I keep my records?

5.14.1 Records shall be in a form suitable and readily available for expeditious review, according to §63.10(b)(1) (40 CFR Part 63, §63.10033(a)).

5.14.2 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.10033(b)).

5.14.3 The Source shall keep each record on site for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1). The Source may keep the records off site for the remaining 3 years (40 CFR Part 63, §63.10033(c)).

The source maintains records as required.

Source is in compliance with this condition.

5.15 §63.10040 What parts of the General Provisions apply to me?

5.15.1 Table 9 of Subpart UUUUU shows which parts of the General Provisions in 40 CFR Part 63, §63.1 through §63.15 apply to the Subpart UUUUU affected EGU.

Source is in compliance with the General Provisions.

Source is in compliance with 40 CFR Part 63, Subpart UUUUU.

6. P101 – Coal Handling System for Units 1 & 2

The coal handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F101a	Coal hauling – Units 1 & 2	$MgCl_2$ or equivalent application
F101b	Coal unloading to grizzly – Units 1 & 2	Water spray with surfactant
F101c	Coal surge pile	Water with surfactant, as necessary
S101d	Primary coal crushing – Units 1 & 2	Baghouse
S101e	Secondary coal crushing building – Units 1 & 2	Baghouse
S101f	Common coal transfer building belt A	Baghouse
S101g	Common coal transfer building belt B	Baghouse
S101h	Coal stackout building – Units 1 & 2	Baghouse
F101i	Coal stackout – Units 1 & 2	Telescopic chute
F101j	Coal storage piles – Units 1 & 2	Water spray prior to stackout, as necessary
S101k	Coal reclaim A – Units 1 & 2	Baghouse
S101l	Coal reclaim B – Units 1 & 2	Baghouse
S101m	Coal tripper deck & silos – Units 1 & 2	Baghouse

Table 5 - P101 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	6.1	3,900,000 tons/year (through each P101 unit)			Recordkeeping	Annually
PM & PM_{10}	6.2	F101a		AP-42, 13.4.2	Recordkeeping and Calculation	Annually
		F101b S101f S101g S101h F101i S101k S101l S101m		PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton		
		S101d		PM: 0.02 lb/ton PM_{10}: 0.009 lb/ton		
		S101e		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		
		F101c F101j				
Opacity	6.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9	Semiannually See Condition 15
Fugitive Emissions	6.4	See Condition 6.4				
Equipment Operation	6.5	See Condition 6.5				

NSPS Y	6.6	Opacity not to exceed 20%		See Condition 6.6

Table 6 - P101 Emissions and Requirements Summary

6.1 Coal consumption must not exceed 3,900,000 tons per year, Colorado Construction Permit 11MF276

6.1.1 Compliance with the annual limit shall be determined on an annual, calendar year basis. Sixty days after the end of the calendar year, a new annual total is calculated.

6.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Units 1 and 2.

6.1.3 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

6.1.4 Records of coal throughput and belt-scale calibrations must be maintained on site for Division inspection upon request.

Unit 1 and 2 coal consumption records were provided for the 2024 calendar year and are included in the table below. The facility uses coal delivery records to comply with this condition, and maintains copies of its coal suppliers' annual scale calibrations.

Tri-State G&T Craig Station Units 1 & 2 Annual Coal Consumption		
Year	**Reported Annual Coal Consumption (tons/yr)**	***Annual Coal Consumption Limit (tons/yr)***
2024	1,548,198	*3,900,000*

Source is in compliance with this condition.

6.2 PM and PM_{10} emissions shall be calculated using the annual coal throughput, emission factors from Table 6 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

6.2.1 For emissions estimates from units without emission factors in Table 6 (F101a, F101c and F101j), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

6.2.2 The Division has approved a 99.0% emission control efficiency for S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

The source calculates estimated emissions from Point 004 annually as required for APEN reporting. The most recent APEN, received by the Division on April 8, 2024, shows 2023 emissions from Units 1 and 2 coal handling as 9.5 tpy and 3.0 tpy for PM and PM_{10}, respectively. The source maintains records of coal handling emissions calculations; however no APEN update was required since the last submittal.

Annual Emissions of PM and PM10 from coal handling from Units 1 & 2 for the 2024 calendar year were provided and are included in the table below.

Tri-State G&T Craig Station Units 1 & 2 Annual Coal Handling Emissions		
Year	**Reported Annual Emissions (tons/yr)**	
	PM	**PM10**
2024	9.35	2.95
Limit:	*NA*	*NA*

Source is in compliance with this condition.

6.3 Opacity

6.3.1 All emission units in this condition, with the exception of the fugitive emission units (F101a, F101b, F101c, F101i, and F101j), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

Coal handing operating were observed to be operating at the time for the inspection. No visible emissions were observed during the inspection. Tri-State is in compliance with the requirements of Condition 15, see Condition 15.

Source is in compliance with this condition.

6.4 Fugitive Emissions – The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 11MF276, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures shall be used to minimize fugitive particulate emissions:

6.4.1 Water with added surfactant must be applied at the grizzly (truck hopper).

6.4.2 The haul road used by coal trucks on the Craig Station property shall be treated with magnesium chloride (or equivalent) to control dust. The treatment material shall be applied as often as necessary to remain viable as a control measure.

6.4.3 The coal being loaded to live storage will be sprayed with water with added surfactant, on an as-needed basis.

6.4.4 Free fall from the stackout tower to the stockpile will be minimized by utilization of telescoping tubes.

6.4.5 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

Surfactant is added to the spray water used at the grizzly.

Tri-State contracts the Trapper Mine to treat its haul roads with magnesium chloride as necessary. Water trucks were observed at the facility during the inspection with no visible emissions were noted coming from the haul roads. No off property transport of visible emissions were observed during the inspection. Property boundaries extend many hundreds of meters past the haul roads and coal piles. The Division received no complaints regarding dust from the facility during the inspection period.

The coal-receiving hopper ("grizzly") is equipped with water/surfactant spray bars triggered by electric eye

when coal is dumped. No visible emissions were observed from coal unloading during the inspection.

The stackout tower is equipped with telescoping chutes as required. Quarterly fugitive emission inspections are performed as required. Tri-State provided records of inspections which were reviewed. No visible emissions were observed from coal loadout from the stackout tower during the inspection and no visible emissions were observed from the transfer point.

Source is in compliance with this condition.

6.5 All process equipment must be maintained and operated such that there is no leakage of air contaminants to the atmosphere prior to their treatment in the pollution control systems. The emission control equipment shall be maintained in accordance with the manufacturer's instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF276). This condition applies to emission units S101d, S101e, S101f, S101g, S101h, S101k, S101l, and S101m. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

No evidence of leakage of air contaminants from process equipment was observed during this inspection. Crushers and conveyors are in complete enclosures.

Source is in compliance with this condition.

6.6 40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants

The following emission units are subject to the requirements of NSPS Y: S101d, S101e, S101f, and S101g.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

6.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

6.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

Coal handing operating were observed to be operating at the time for the inspection. No visible emissions were observed during the inspection.

7. P102 – Coal Handling System for Unit 3

P102 may be used at times for blending coal used in Units 1 and 2. The coal handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F102a	Coal train unloading – Unit 3	Water spray
S102b	Coal conveyor portal building – Unit 3	Baghouse
S102c	Coal conveyor portal building – Unit 3	Baghouse
S102d	Secondary coal crushing (2 crushers) – Unit 3	Baghouse
S102e	Coal stackout building – Unit 3	Baghouse
F102f	Coal stackout – Unit 3	Telescopic chutes
F102g	Coal storage pile – Unit 3	PM control plan, including compaction, chemical use or watering, as necessary
S102h	Coal reclaim system – Unit 3	Baghouse
S102i	Coal tripper deck & silos – Unit 3	Baghouse
S102j	Loadout coal to railcars – Unit 3	Baghouse
S102k	Common coal transfer building extension	Baghouse
F102l	Coal train loading	N/A

Table 7 - P102 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Coal Consumption	7.1	4,500,000 tons/year (each unit but tripper deck) 1,897,344 tons/year (tripper deck) Coal Storage Pile: ≤ 14.5 acres			Recordkeeping	Monthly
PM & PM_{10}	7.2	F102a S102b S102c S102e F102f S102h S102k S102i S102j	PM: 1.7 tons/year (all units combined) PM_{10}: 0.7 tons/year (all units combined)	PM: 2.22×10^{-4} lb/ton PM_{10}: 1.05×10^{-4} lb/ton	Recordkeeping and Calculation	Monthly
		S102d		PM: 0.05 lb/ton PM_{10}: 0.02 lb/ton		
		F102g F102l				
Opacity	7.3	Not to exceed 20% opacity except during certain operational activities at			EPA Reference Method 9	Semiannually See Condition 15

		which time not to exceed 30% opacity			
Fugitive Emissions	7.4	See Condition 6.4			
Required Controls	7.5	See Condition 7.5			
NSPS Y	7.6	Opacity not to exceed 20%		See Condition 7.6	
CAM	7.7	Condition 7.7			

Table 8 - P102 Emissions and Requirements Summary

7.1 Coal consumption, Colorado Construction Permit 12MF322-2

Coal throughput must not exceed 4,500,000 tons per year (all units except for tripper deck)

Coal throughput through the tripper deck must not exceed 1,897,344 tons per year

Coal storage pile must not exceed 14.5 acres in size

7.1.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.1.2 Compliance with this limit will be monitored on a monthly basis using belt scales to measure coal throughput into the coal handling system for Unit 3. Throughput to the tripper deck must be monitored separately.

7.1.3 Compliance with the coal storage pile limit must be certified on a once per calendar year basis. The Source must provide to the Division the methodology for the measurement. At the Division's discretion, the Division may require an alternative methodology for the measurement.

7.1.4 The belt scales must be calibrated at least once per calendar year with at least 180 days between calibrations.

7.1.5 Records of coal throughput, coal storage pile certifications, and belt-scale calibrations must be maintained on site for Division inspection upon request.

The source tracks monthly and 12-month rolling coal handling as required. Tri-State provided throughput records that are summarized in the table below. The facility uses coal delivery records to comply with this condition and maintains copies of its coal suppliers' annual scale calibrations. The coal storage pile is not larger than 14.5 acres.

Tri-State G&T Craig Station Unit 3 Annual Coal Handling Throughput		
Period	**Reported Throughputs (tons/yr)**	
	Total Coal Handling	**Coal Through the Tripper Deck/Coal Burned**
3/2023-2/2024	1,956,893	1,072,611
1/2024-12/2024	1,674,327	739,506
2/2024-1/2025	1,566,270	685,170
Limit:	*4,500,000*	*1,897,344*

The source did not exceed coal handling limits during the inspection period.

Source is in compliance with this condition.

7.2 PM emissions must not exceed 1.7 tons per year, PM_{10} emissions must not exceed 0.7 tons per year, Colorado Construction Permit 12MF322-2

7.2.1 Compliance with the annual limits shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

7.2.2 Emissions shall be calculated using the annual coal throughput, emission factors from Table 8 (AP-42, Sections 13.2.4 (November 2006) and 11.24 (August 1982); UARG P-A857 (1981)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = coal\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

7.2.3 For emission estimates from units without emission factors in Table 8 (F102g, F102l), appropriate emission factors or equations shall be used. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

7.2.4 The Division has approved a 99.0% emission control efficiency for S102b, S102c, S102d, S102e, S102h, S102i, S102j, and S102k. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

Tri-State maintains monthly and 12 month rolling records of PM emissions from Unit 3 coal handling operations as required. Records of the PM emissions for the Unit 3 coal handling operations were provided and are summarized in the table below. A review of records provided indicates the Tri-State has not exceeded emissions limits for the Unit 3 coal handling activities.

Tri-State G&T Craig Station Unit 3 Annual Coal Handling Emissions		
Period	**Reported Emissions (tons/yr)**	
	PM	**PM10**
3/2023-2/2024	0.88	0.39
1/2024-12/2024	0.79	0.35
2/2024-1/2025	0.76	0.34
Limit:	*1.7*	*0.7*

Source is in compliance with this condition.

7.3 Opacity

7.3.1 All emission units in this condition, with the exception of the fugitive emission units (F102a, F102f, F102g, and F102l), are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

Coal Handling for Unit 3 was not operating at the time of the inspection. No visible emissions were observed during the inspection. Tri-State is in compliance with the requirements of Permit Condition 15 (see Permit Condition 15).

Source is in compliance with this condition.

7.4 Fugitive Emissions – The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. (Colorado Construction Permit 12MF322-2, as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit). The following measures represent BACT for PM and PM_{10} and must be used to minimize fugitive particulate emissions:

7.4.1 The train dump area must be equipped with water spray bars which shall be operated whenever a load of coal is dumped, as needed, to minimize fugitive dust emissions. The spray nozzles shall be positioned so as to achieve the greatest effectiveness in dust control.

7.4.2 Adjustable chutes must be used to transfer coal to the stockpiles. These chutes shall minimize the free fall distance from the chute outlet to the pile.

7.4.3 Control measures must be taken as necessary to minimize fugitive coal dust emissions from the coal storage pile. These control measures shall include compaction, spraying the piles with water, or if necessary, a chemical stabilizer.

7.4.4 A quarterly inspection shall be performed to ensure the measures listed in this condition are in place and effective. Compliance shall be certified on an annual basis. Records of inspections shall be maintained and made available for inspection upon request.

The source uses a partially enclosed coal unloading area equipped with spray bars. Sufficient moisture is maintained in the coal for dust mitigation. Adjustable chutes are used for dumping into the coal pile. Chemical stabilizer is added as needed to control dust. Records of quarterly inspections were provided and indicate the required measure are being implemented. The Division received no complaints regarding coal dust coming from Craig Station during the inspection period. The source was not operating at the time of the inspection with minimal visible emissions present.

Source is in compliance with this condition.

7.5 Fabric filter baghouses shall be employed to control dust emissions from crushing operations, transferring operations, and reclaiming of coal (Colorado Construction Permit, 12MF322-2). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

The source utilizes fabric filter baghouses to control dust from crushing, transferring and reclaiming of coal as required. Tri-State is in compliance with the requirements of Permit Condition 16 (see Permit Condition 16)

Source is in compliance with this condition.

7.6 40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation and Processing Plants

The following emission units are subject to the requirements of NSPS Y: F102a, S102b, S102c, S102d, S102h, S102j, S102k, and F102l.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart Y published in the Federal Register on October 8, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

7.6.1 The Source shall not cause to be discharged into the atmosphere from any coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal, any gases which exhibit 20 percent opacity or greater (40 CFR Part 60, §60.254(a)).

7.6.2 The Source must conduct all performance tests required by §60.8 to demonstrate compliance with the applicable emission standards using them methods identified in §60.257 (40 CFR Part 60, §60.255(a)).

Coal Handling for Unit 3 was not operating at the time of the inspection. No visible emissions were observed during the inspection. Tri-State is in compliance with the requirements of Permit Condition 15 (see Permit Condition 15).

Source is in compliance with this condition.

7.7 Compliance Assurance Monitoring (CAM)

The secondary coal crushing building (S102d) is subject to 40 CFR Part 64 requirements associated with CAM with respect to the PM limitations in Condition 7.2. Compliance with the CAM requirements shall be monitored in accordance with the requirements in Condition 22 and Appendix I.

Source is in compliance with CAM requirements, See condition 7.2. Cam requirements are monitored consistent with the requirements in Condition 22 and Appendix I.

Source is in compliance with this condition.

8. P201 – Limestone Handling and Storage Facility for Units 1 and 2

The limestone handling and storage facility for Units 1 and 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F201a	Limestone hauling	Paved portions of road
S201b	Limestone truck unloading	Baghouse
S201c	Limestone silo #1 – Units 1 & 2	Baghouse
S201d	Limestone silo #2 – Units 1 & 2	Baghouse
N/A	Limestone conveying	Building enclosure

Table 9 – P201 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Limestone Delivery	8.1				Recordkeeping	Annually
PM & PM_{10}	8.2	F201a		PM: Paved: 3.97 Unpaved: 10.3 PM_{10}: Paved: 0.79 Unpaved: 2.9 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Annual
		S201b S201c S201d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	8.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
Baghouse	8.4	See Condition 8.4				
Equipment Operation	8.5	See Condition 8.5				
NSPS OOO (conveying only)	8.6	Opacity not to exceed 7%				

Table 10 – P201 Emissions and Requirements Summary

This section covers requirements for AIRS Point 020. Limestone handling was observed to be operating at the time of the inspection.

8.1 Records of the annual quantity (in tons) of limestone delivered for P201 must be maintained and made available for Division inspection upon request.

Tri-State maintains annual records of limestone delivered as required. Records were provided for the 2024 calendar year and are included in the table below.

Tri-State G&T Craig Station Units 1 & 2 Limestone Delivered	
Year	**Reported Limestone Delivered (tons/yr)**
2024	24,699
Limit:	*NA*

Source is in compliance with this condition.

8.2 Emissions shall be calculated using the annual limestone throughput (estimated as limestone delivered to the facility), emission factors from Table 10 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

8.2.1 For F201a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 10. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

8.2.2 The Division has approved a 99.0% emission control efficiency for S201b, S201c, and S201d. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

Tri-State maintains records of limestone handling and calculates emissions as required. Annual Emissions of PM and PM10 from limestone handling from Units 1 & 2 for the 2023 calendar year were provided and are included in the table below. Baghouse maintenance records were provided indicating that the baghouses are operated and maintained consistent with the recommendations of the manufacturers and good engineering practices.

Tri-State G&T Craig Station Units 1 & 2 Annual Limestone Handling Emissions		
Year	**Reported Annual Emissions (tons/yr)**	
	PM	**PM10**
2024	3.26	0.70
Limit:	*NA*	*NA*

Source is in compliance with this condition.

8.3 Opacity

8.3.1 All emission units in this condition, with the exception of the fugitive emission units (F201a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

Limestone handling was operating at the time of the inspection. No visible emissions were observed during the inspection. Source is in compliance with this requirements of Permit Condition 15 (see Permit Condition 15).

Source is in compliance with this condition.

8.4 The unloading facilities (S201b) must be vented to a baghouse (Colorado Construction Permit 11MF415). Baghouse operation and maintenance must follow the requirements described in Condition 16 (Colorado Regulation No. 3, Part C, Section V.C.5.).

The limestone truck unloading facilities are vented to a baghouse as required. Records were provided indicating that that operating and maintenance procedures are conducted consistent with requirements of Permit Condition 16 (see Permit Condition 16).

Source is in compliance with this condition.

8.5 All process equipment (S201b, S201c, S201d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 11MF415). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

Records were provided indicating that operating and maintenance procedures are conducted consistent with requirements of Permit Condition 16 on the baghouses associated with limestone handling (see Permit Condition 16).

Source is in compliance with this condition.

8.6 40 CFR Part 60, Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants

The following emission units are subject to the requirements of NSPS OOO: limestone belt conveyors. The applicability date for Subpart OOO was August 31, 1983; any facility which commenced construction, modification, or reconstruction after this date is subject. The Source must maintain a log of which pieces of the limestone conveying system are subject to each of the following provisions of NSPS OOO for Division inspection upon request.

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 60, Subpart OOO published in the Federal Register on April 28, 2009. However, if revisions to this Subpart are published at a later date, the Source is subject to the revised requirements, as applicable.

Units subject to an NSPS are also subject to the 40 CFR Part 60, Subpart A, General Provisions requirements as described in Condition 18.

8.6.1 If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in §60.672(a) and (b), or the building enclosing the affected facility or facilities must comply with the following emission limit (40 CFR Part 60, §60.672(e)):

8.6.1.1 Fugitive emissions from the building openings (except for vents as defined in §60.671) must not exceed 7 percent opacity (40 CFR Part 60, §60.672(e)(1)).

8.6.2 The Source must submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in in §60.672 of Subpart OOO, including reports of opacity observations made using Method 9 to demonstrate compliance with §60.672(b) and (e) (Condition 8.6.1) (40 CFR Part 60, §60.676(f)).

8.6.3 The conveyors subject to Subpart OOO in this condition are also subject to the provisions of 40 CFR Part 60, Subpart A, General Provisions as described in Condition 18.

Limestone handling was operating at the time of the inspection. No visible emissions were observed from limestone handling activities during the inspection. Source is in compliance with the requirements of Permit Condition 18 (see Permit Condition 18).

Source is in compliance with this condition.

9. P202 – Lime Handling and Storage Facility for Unit 3

The lime handling and storage facility for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
F202a	Lime hauling	Paved portions of road
S202b	Lime unloading	Baghouse
S202c	Lime conveying and silo	Baghouse
S202d	Lime day bin	Baghouse

Table 11 – P202 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Lime Delivery	9.1	28,000 tons/year via truck 28,000 tons/year via rail			Recordkeeping	Monthly
PM & PM_{10}	9.2	F202a	PM: 14.9 tons/year, 12-month rolling total (all units combined) PM_{10}: 2.9 tons/year, 12-month rolling total (all units combined)	PM: Paved: 5.39 Unpaved: 11.84 PM_{10}: Paved: 1.08 Unpaved: 3.37 EF in lb per vehicle mile traveled	Recordkeeping and Calculation	Monthly
		S202b S202c S202d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton		
Opacity	9.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-4 Baghouses	9.4	See Condition 9.4				
Equipment Operation	9.4.3	See Condition 9.4.3				

Table 12 – P202 Emissions and Requirements Summary

9.1 Throughput of lime must not exceed 28,000 tons per year via truck, and 28,000 tons per year via rail (Colorado Construction Permit 12MF322-4)

9.1.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data

9.1.2 Monthly records of the quantity (in tons) of lime throughput for P202 must be maintained and made available for Division inspection upon request. These records must specify whether the lime was delivered via truck or via rail.

The source maintains monthly and 12-month rolling total records of lime delivery as required. The source provided records of lime delivery for the inspection period that are summarized in the table below. The source only receives lime via truck at this time. No lime was delivered via rail during the inspection period.

Tri-State G&T Craig Station Unit 3 Annual Lime Throughput		
Period	**Reported Throughputs (tons/yr)**	
	Lime Delivered by Truck	**Lime Delivered by Rail**
3/2023-2/2024	14,935	0
1/2024-12/2024	8,560	0
2/2024-1/2025	9,577	0
Limit:	*28,000*	*28,000*

The source did not exceed the abovementioned delivery limits during the inspection period.

Source is in compliance with this condition.

9.2 PM and PM_{10} emissions must not exceed 14.9 tons per year and 2.9 tons per year, respectively, for all P202 emission units combined (Colorado Construction Permit 12MF322-4)

9.2.1 Compliance with the annual limit shall be determined on a rolling twelve-month total. By the end of each month a new twelve-month total is calculated using the previous twelve-months' data.

9.2.2 Emissions shall be calculated using the actual lime throughput (as required in Condition 9.1), emission factors from Table 12 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = limestone\ throughput\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

9.2.3 For F202a, emissions shall be calculated using AP-42, Section 13.2.4 (November 2006) and the emission factors in Table 12. Records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

9.2.4 The Division has approved a 99.0% emission control efficiency for S202b, S202c, and S202d, and a 90% emission control efficiency for F202a. The acceptance of these control efficiencies is contingent on continued routine maintenance of and operation procedures performed on the control devices in accordance with manufacture's specifications and good engineering practices. These procedures and maintenance schedules shall be maintained on site and provided for Division inspection upon request.

Tri-State maintains monthly and 12 month rolling records of PM emissions from Unit 3 lime handling operations as required. Records of the PM emissions for the Unit 3 lime handling operations were provided and are summarized in the table below. A review of records provided indicates the Tri-State has not exceeded emissions limits for the Unit 3 lime handling activities.

Tri-State G&T Craig Station Unit 3 Annual Lime Handling Emissions		
12-Month Period Ending	**Reported Emissions (tons/yr)**	
	PM	**PM10**
3/2023-2/2024	3.54	0.72
1/2024-12/2024	2.03	0.41
2/2024-1/2025	2.27	0.46
Limit:	*14.9*	*2.9*

The source did not exceed any PM emission limits during the inspection period.

Source is in compliance with this condition.

9.3 Opacity

9.3.1 All emission units in this condition, with the exception of the fugitive emission units (F202a) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

Limestone handling was not operating at the time of the inspection. No visible emissions were observed during the inspection. Source is in compliance with this requirements of Permit Condition 15 (see Permit Condition 15).

Source is in compliance with this condition.

9.4 Colorado Construction Permit 12MF322-4

9.4.1 The bulk lime unloading facilities (S202b) must be vented to a baghouse. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.2 The lime silo must be vented to a fabric filter baghouse to control emissions from unloading and working losses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

9.4.3 All process equipment (S202b, S202c, S202d) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter (Colorado Construction Permit 12MF322-4). The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

The limestone truck and rail unloading facilities are vented to a baghouse as required. Records were provided indicating that that operating and maintenance procedures are conducted consistent with requirements of Permit Condition 16 (see Permit Condition 16).

Source is in compliance with this condition.

10. P203 – Ash Handling System for Units 1 & 2

The ash handling system for Units 1 & 2 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S203a	Ash storage silo A – Units 1 & 2	Baghouse (Shared with S203e)
S203b	Ash storage silo B – Units 1 & 2	Baghouse (Shared with S203d)
F203c	Ash truck loading – Units 1 & 2	Low dust unloader
S203d	Silo B dry ash unloading – Units 1 & 2	Baghouse (Shared with S203b)
S203e	Silo A dry ash unloading – Units 1 & 2	Baghouse (Shared with S203a)

Table 13 – P203 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Ash Processed	10.1				Recordkeeping	Annually
PM & PM_{10}	10.2	S203a S203e S203b S203d		PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Annually
		F203c		PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton		
Opacity	10.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity			EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
11MF332 Process Requirements	10.4	See Condition 10.4				

Table 14 – P203 Emissions and Requirements Summary

This section covers requirements for AIRS Point 016. Ash handling for units 1 and 2 was operating at the time of the inspection.

10.1 Records of the estimated quantity (in tons) of ash processed for P203 must be maintained and made available for Division inspection upon request. Ash quantities are estimated from the number of trucks loaded and the average truck load capacity (Colorado Regulation No. 3, Part C, Section V.C.5.).

Tri-State provided annual ash handling records for the 2024 calendar year that are included in the table below.

Tri-State G&T Craig Station Units 1 & 2 Annual Ash Handled	
Year	**Ash Handled (tons/yr)**
2024	24,920
Limit:	*NA*

Source is in compliance with this condition.

10.2 Emissions shall be calculated using the annual ash throughput, emission factors from Table 14 (AP-42, Section 13.2.4 (November 2006)), and Division-approved control equipment control efficiencies, in the following equation (Colorado Regulation No. 3, Part C, Section V.C.5.):

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

10.2.1 The Division has approved a 99.0% emission control efficiency for S203a and S203b. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

Annual Emissions of PM and PM10 from ash handling for the 2024 calendar year were provided and are included in the table below.

Tri-State G&T Craig Station Units 1 & 2 Annual Ash Handling Emissions		
Year	**Reported Annual Emissions (tons/yr)**	
	PM	**PM10**
2024	0.010	0.005
Limit:	*NA*	*NA*

Source is in compliance with this condition.

10.3 Opacity

10.3.1 All emission units in this condition, with the exception of the fugitive emission units (F203c) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

Ash handling for Units 1 & 2 was operating at the time of the inspection. No visible emissions were observed during the inspection. Source is in compliance with this requirements of Permit Condition 15 (see Permit Condition 15).

Source is in compliance with this condition.

10.4 Colorado Construction Permit 11MF332 (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

10.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

10.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 10.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

10.4.3 Fugitive Emissions – The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

10.4.3.1 Ash for disposal must be loaded through chutes into the trucks. Ash leaving the chutes and loaded into trucks for disposal must be sufficiently wet to minimize fugitive dust emissions.

10.4.3.2 Deposition of mud and dirt on improved public streets and roads must be prevented, as necessary, to control fugitive dust emissions.

10.4.4 All process equipment (S203a, S203b, S203d, S203e) must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

Both ash silos and unloaders are equipped with baghouses as required. Ash for disposal is conditioned with water prior to being loaded into trucks. Quarterly fugitive dust and visible emissions inspections are performed as required. Inspection records were reviewed during the inspection show no indication of visible emissions. The source reported that ash is not transported on public roads. No mud or dirt deposition was observed on public roads around the facility during the inspection.

Tri-State reported fugitive emissions from the S203a Ash Storage Silo A dry ash truck loading that occurred on August 16, 2024 from 10:30 AM to 11:30 AM in violation of Condition 10.4.1. The event was properly reported as a malfunction, was determined to be a valid malfunction and to qualify for the affirmative defense form enforcement (see Malfunction Section).

Source is <u>not in compliance</u> with this condition.

11. P204 – Ash Handling System for Unit 3

The ash handling system for Unit 3 includes the following emission units:

Facility Stack ID	Description	Pollution Control
S204a	Ash storage silo C – Unit 3	Baghouse
F204b	Ash truck loading (wet flyash and dry flyash) – Unit 3	Low dust loader (wet ash) Baghouse (Only for dry fly ash loading)
S204c	Recycle ash tank	Baghouse
F204d	Ash haul road (ash and scrubber sludge hauling) – Units 1, 2, & 3	$MgCl_2$ application on roads

Table 15 – P204 Emission Units Description

Parameter	Permit Condition Number	Limitation		Compliance Emission Factor	Monitoring	
					Method	Interval
Ash Throughput	11.1	Unit 3 flyash handling: 174,649 tons/year Unit 3 ash and scrubber sludge handling: 237,247 tons/year			Recordkeeping	Monthly
PM & PM_{10}	11.2	S204a S204c	PM: 76.6 tons/year (all units combined) PM_{10}: 16.1 tons/year (all units combined)	PM: 0.012 lb/ton PM_{10}: 0.006 lb/ton	Recordkeeping and Calculation	Monthly
		F204b		Flyash loading: PM: 0.0005 lb/ton PM_{10}: 0.0002 lb/ton Dry ash unloading: PM: 0.081 lb/ton PM_{10}: 0.039 lb/ton From AP-42, 13.2.4 Assume: U = 8.1 mph, M = 0.25%		
		F204d		PM: Paved: 6.39 Unpaved: 12.76 PM_{10}: Paved: 1.28 Unpaved: 3.6 EF in lb per vehicle mile traveled		

Opacity	11.3	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		EPA Reference Method 9 Bagfilter O&M	Semiannually Ongoing O&M
12MF322-3 Process Requirements	11.4	See Condition 11.4			

Table 16 – P204 Emissions and Requirements Summary

This section covers requirements for AIRS Point 016. Ash handling for Unit 3 was not operating at the time of the inspection.

11.1 Unit 3 flyash handling must not exceed 174,649 tons per year, Unit 3 ash and scrubber sludge handling must not exceed 237,247 tons per year, Colorado Construction Permit 12MF322-3

11.1.1 Compliance with the annual throughput limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.1.2 Records of the quantity (in tons) of Unit 3 flyash handled and Unit 3 ash and scrubber sludge handled must be maintained and made available for Division inspection upon request.

The source tracks monthly and 12-month rolling ash handling as required. Tri-State provided throughput records that are summarized in the table below.

Tri-State G&T Craig Station Unit 3 Annual Ash Handling Throughput		
Period	**Reported Throughputs (tons/yr)**	
	Fly Ash Handling	**Ash and Scrubber Sludge Handling**
3/2023-2/2024	109,709	91,875
1/2024-12/2024	68,469	60,744
2/2024-1/2025	65,102	55,919
Limit:	*174,649*	*237,247*

The source did not exceed ash handling limits during the inspection period.

Source is in compliance with this condition.

11.2 PM emissions must not exceed 76.6 tons per year, PM_{10} emissions must not exceed 16.1 tons per year, Colorado Construction Permit 12MF322-3

11.2.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

11.2.2 Emissions shall be calculated using the annual ash throughputs, emission factors from Table 16 (AP-42, Section 13.2.4 (November 2006), note that F204b includes emission factors for both flyash loading and dry ash unloading), and Division-approved control equipment control efficiencies, in the following equation:

$$\frac{tons}{year} = ash\ processed\ \left[\frac{tons}{year}\right] * \ emission\ factor\ \left[\frac{lb}{ton}\right] * (1 - control\ \%) * \frac{1\ ton}{2000\ lb}$$

11.2.3 For emission estimates from units which reference AP-42, Section 13.4.2 (November, 2006) in Table 16, records of the emissions calculations must be maintained and made available to the Division for inspection upon request.

11.2.4 The Division has approved a 99.0% emission control efficiency for S204a and S204c, a 90.0% emission control efficiency for F204d ash haul road, and 80% and 99% emission control efficiencies for F204b wet flyash loading, and F204b dry ash loading, respectively. The acceptance of these control efficiencies shall only be granted provided that the Source operates and maintains the control devices in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

Tri-State maintains monthly and 12 month rolling records of PM and PM10 emissions from Unit 3 ash handling operations as required. Records of the PM and PM10 emissions for the Unit 3 ash handling operations were provided and are summarized in the table below. A review of records provided indicates the Tri-State has not exceeded emissions limits for the Unit 3 ash handling activities.

Tri-State G&T Craig Station Unit 3 Annual Ash Handling Emissions		
Period	**Reported Emissions (tons/yr)**	
	PM	**PM10**
3/2023-2/2024	37.7	8.2
1/2024-12/2024	36.5	7.9
2/2024-1/2025	36.3	7.9
Limit:	*76.6*	*16.1*

Source is in compliance with this condition.

11.3 Opacity

11.3.1 All emission units in this condition, with the exception of the fugitive emission units (F204b ash truck loading, and F204d ash haul road) are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15.

Ash handling for Unit 3 was not operating at the time of the inspection. No visible emissions were observed during the inspection. Source is in compliance with this requirements of Permit Condition 15 (see Permit Condition 15).

Source is in compliance with this condition.

11.4 Colorado Construction Permit 12MF322-3 (as adopted and revised in accordance with the provisions of Section I, Condition 1.3 of this Operating Permit)

11.4.1 Ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses. Baghouse operation and maintenance must follow the requirements described in Condition 16.

11.4.2 Quarterly inspections must be performed to verify the measures listed in Condition 11.4 are in place and effective. Records of inspections must be maintained and made available to the Division for inspection upon request.

11.4.3 Fugitive Emissions – The Source is subject to the Fugitive Particulate Emissions requirements of Colorado Regulation No. 1, Section III.D. The following measures shall be used to minimize fugitive particulate emissions:

11.4.3.1 Ash loaded into trucks for disposal must be sufficiently wet to control fugitive dust emissions.

11.4.3.2 A low dust unloading system must be employed to load the ash hauling trucks for ash disposal. Ash leaving these unloaders must be sufficiently wet to minimize fugitive emissions.

11.4.3.3 All components of the ash conveying system must be dust tight to eliminate leaks in the system.

11.4.3.4 The scrubber sludge and ash haul road for Units 1, 2, and 3 must be treated with magnesium chloride ($MgCl_2$), or equivalent, as a dust suppressant. The $MgCl_2$ must be applied in accordance as necessary in accordance with good air pollution control practices to minimize the emission of fugitive dust.

11.4.4 All process equipment must be maintained and operated so as to minimize leakage of air contaminants to the atmosphere prior to their treatment in the pollution control system. The emission control equipment must be maintained in accordance with the manufacturers' instructions to achieve continuous control of particulate matter. The Source must perform the appropriate operation and maintenance of the control device/s in accordance with the requirements of Condition 16 Colorado Regulation No. 3, Part C, Section V.C.5.).

The ash silo and dry ash unloader are vented to fabric filter baghouses as required. Ash hauling from Unit 3 was not operating during the inspection. Quarterly fugitive dust and visible emissions inspections are performed as required. Inspection records were reviewed during the inspection show no indication of visible emissions. The source stated ash is sufficiently moist during transport. No visible emissions were reported during the inspection. There is no evidence to suggest that the conveying system contains leaks.

Source is in compliance with this condition.

12. S401 & S402 – Units 1 & 2 Cooling Towers

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	12.1	Maximum Pumping Capacity: 180,000 gallons/minute (per tower)		Design Limitation Certification	Annually
Total Dissolved Solids	12.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	12.3	PM: 27.2 tons/year PM_{10}: 27.2 tons/year	TDS Sampling See Condition 12.3	Recordkeeping and Calculation	Annually
VOC	12.4	5.0 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Annually
Opacity	12.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 12.5	

Table 17 – S401 & S402 Emissions and Requirements Summary

12.1 The cooling tower water flow rate must not exceed 180,000 gallons per minute (per tower), Colorado Construction Permit 96MF195

12.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system (153,000 gallons per minute). The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

12.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

Tri-State reported that the maximum pumping capacity of the towers is 153,000 gal/min. No design changes have occurred that would result in an increase in pumping capacity. Tri-State certifies compliance with this requirement annually as required.

Source is in compliance with this condition.

12.2 Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 96MF195

12.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

12.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division-approved test method.

12.2.2.1 Monthly samples must be taken at least seven (7) days apart.

12.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration

shall be the average of all samples taken, as appropriate.

12.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 12.2), and results must be maintained and made available for Division inspection upon request.

TDS samples are collected and analyzed weekly. Records for the inspection period were reviewed. Tri-State did not report any concentrations greater than 11,040 mg/l during the inspection period.

Source is in compliance with this condition.

12.3 PM and PM_{10} emissions must not exceed 27.2 tons per year (combined emissions), Colorado Construction Permit 96MF195

12.3.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

Tri-State provided annual records of PM and PM10 emissions calculations for the Units 1 and 2 Cooling Towers for the 2024 calendar year that are included in the table below. Emissions were calculated using the required methodology. Tri-State has not exceeded the annual PM and PM10 emissions limits.

Tri-State G&T Craig Station Units 1 and 2 Annual Cooling Tower PM and PM10 Emissions		
Period	**Reported Emissions (tons/yr)**	
	PM	**PM10**
2024	12.0	12.0
Limit:	*27.2*	*27.2*

Source is in compliance with this condition.

12.4 VOC emissions must not exceed 5.0 tons per year (combined emissions), Colorado Construction Permit 96MF195

12.4.1 Compliance with the annual emission limits shall be based on a calendar year, twelve-month total.

12.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 17 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

Tri-State provided annual records of VOC emissions calculations for the Units 1 and 2 Cooling Towers for the 2024 calendar year that are included in the table below. Emissions were calculated using the required methodology. Tri-State has not exceeded the annual VOC emissions limit.

Tri-State G&T Craig Station Units 1 and 2 Annual Cooling Tower VOC Emissions	
Period	**Reported Emissions (tons/yr)**
	VOC
2024	4.8
Limit:	*5.0*

Source is in compliance with this condition.

12.5 Opacity

12.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

The Units 1 and 2 Cooling Towers were operating at the time of the inspection. No visible emissions were observed during the inspection. Maintenance procedures and maintenance records were reviewed during the inspection and were determined to be adequate.

Source is in compliance with this condition.

13. S403 – Unit 3 Cooling Tower

Parameter	Permit Condition Number	Limitation	Compliance Emission Factor	Monitoring	
				Method	Interval
Circulating Water Rate	13.1	Maximum Pumping Capacity: 180,000 gallons/minute		Design Limitation Certification	Annually
Total Dissolved Solids	13.2	11,040 milligrams/liter		Sampling and Testing	Monthly
PM & PM_{10}	13.2.2	PM: 13.6 tons/year PM_{10}: 13.6 tons/year	TDS Sampling See Condition 13.2.2	Recordkeeping and Calculation	Monthly
VOC	13.4	2.5 tons/year	0.0527 lb/10^6 gallons	Recordkeeping and Calculation	Monthly
Opacity	13.5	Not to exceed 20% opacity except during certain operational activities at which time not to exceed 30% opacity		See Condition 13.5	

Table 18 – S403 Emissions and Requirements Summary

13.1 The cooling tower water flow rate must not exceed 180,000 gallons per minute, Colorado Construction Permit 98MF0141.

13.1.1 Compliance with this requirement is presumed based on the physical design limitations of the pumping system. The Source will notify the Division if there have been any changes to the system which may allow for the potential flow rate to exceed this limitation, at which time the Source will submit a modification to this Operating Permit.

13.1.2 On an annual basis, the Source must certify that there have been no changes to the cooling tower water pump system that would allow for this limitation to be exceeded.

An average flow rate of 170,328 gal/min was calculated for 2024 based on the total water processed. The maximum pumping capacity of the towers is 180,000 gal/min. No design changes have occurred that would result in an increase in pumping capacity. Tri-State certifies compliance with this requirement annually as required.

Source is in compliance with this condition.

13.2 Total dissolved solids (TDS) in the cooling tower water must not exceed 11,040 milligrams per liter, Colorado Construction Permit 98MF0141

13.2.1 This limit corresponds to a water hardness of 2,000 milligrams per liter of calcium carbonate which is the maximum limit for satisfactory performance of scale inhibitors in the boilers and heat exchangers.

13.2.2 Compliance with this limit will be determined by monthly sampling and testing of the cooling tower water to determine TDS concentration using a Division approved test method.

13.2.2.1 Monthly samples must be taken at least seven (7) days apart.

13.2.2.2 In the event that more frequent sampling occurs, the monthly TDS concentration

shall be the average of all samples taken, as appropriate.

13.2.2.3 Records of all TDS sampling and testing methodologies, Division test-method approval/s (per Condition 13.2), and results must be maintained and made available for Division inspection upon request.

Tri-State samples the cooling tower water on a weekly basis and reported that TDS concentrations did not exceed 11,040 mg/liter during the inspection period. Typical TDS concentrations are between 2,000 and 6,000 mg/L. At no time during the inspection period did the source exceed the TDS limit.

Source is in compliance with this condition.

13.3 PM and PM_{10} emissions must not exceed 13.6 tons per year, Colorado Construction Permit 98MF0141.

13.3.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.3.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, the weighted average drift rate, TDS concentration (as determined in the sampling as required in Condition 12.2 in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor\ (TDS) \left[\frac{lb}{MMgallons}\right] * weighted\ average\ drift\ rate \left[\frac{gallon}{gallon}\right] * \frac{1\ ton}{2000\ lb}$$

Note that the Division has approved of the designed maximum drift loss of 0.001 percent. The time operated per month is assumed to be the same as for the associated boiler.

Tri-State maintains monthly and 12 month rolling records of PM and PM10 emissions from Unit 3 cooling towers as required. The 12-month rolling total emissions from Unit 3 were provided and are summarized in the table below. The source did not exceed PM or PM10 emission limits during the inspection period.

Tri-State G&T Craig Station Unit 3 Annual Cooling Tower PM and PM10 Emissions		
Period	**Reported Emissions (tons/yr)**	
	PM	**PM10**
3/2023-2/2024	4.7	4.7
1/2024-12/2024	3.7	3.7
2/2024-1/2025	3.5	3.5
Limit:	*13.6*	*13.6*

Source is in compliance with this condition.

13.4 VOC emissions must not exceed 2.5 tons per year, Colorado Construction Permit 98MF0141.

13.4.1 Compliance with the annual emission limits shall be based on a rolling twelve-month total. At the end of each month, a new twelve-month total is calculated based on the previous twelve-month's data.

13.4.2 Monthly emissions shall be calculated using the maximum water flow rate, time operated per month, and emission factor from Table 18 (letter from Micheletti to Tri-State, November 11, 1992) in the following equation:

$$\frac{tons}{month} = 0.180000 \left[\frac{MMgallons}{minute}\right] * time\ operated \left[\frac{minutes}{month}\right] * emission\ factor \left[\frac{lb}{MMgallons}\right] * \frac{1\ ton}{2000\ lb}$$

Tri-State maintains monthly and 12 month rolling records of VOC emissions from Unit 3 cooling towers as required. The 12-month rolling total emissions from Unit 3 were provided and are summarized in the table below. The source did not exceed the VOC emission limit during the inspection period.

Tri-State G&T Craig Station Unit 3 Annual Cooling Tower VOC Emissions	
Period	**Reported Emissions (tons/yr)**
	VOC
3/2023-2/2024	2.2
1/2024-12/2024	1.7
2/2023-2/2025	1.7
Limit:	*2.5*

Source is in compliance with this condition.

13.5 Opacity

13.5.1 The cooling towers in this condition are subject to the Colorado Regulation No. 1 opacity requirements of Condition 15. However, in the absence of credible evidence to the contrary, compliance with these limits shall be presumed provided that the Source operates and maintains the cooling towers and the drift eliminators in accordance with manufacture's recommendations and good engineering practices. A copy of the operating and maintenance procedures, schedules for maintenance and/or inspection activities and records related to the operation and maintenance of the control devices, and good engineering practices such as records of routine maintenance and/or inspections, shall be maintained and made available to the Division upon request.

The Unit 3 Cooling Tower was not operating at the time of the inspection. No visible emissions were observed during the inspection. Maintenance procedures and maintenance records were reviewed during the inspection and were determined to be adequate.

Source is in compliance with this condition.

14. Emergency Diesel Engines

The emergency fire-pump engine, Units 1 & 2 emergency diesel generator engine, and the Unit 3 emergency diesel generator engine (see Table 1 for relevant make, model, and serial numbers) are emission units covered under this condition. At the time of issuance of this Operating Permit, these engines do not require emission limits because they are exempt under Colorado Regulation No. 3, Part C, Section II.E.3.nnn.(iii) since they have fewer than five (5) tons per year of actual emissions.

14.1 Except as provided in Condition 14.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity (Colorado Regulation No. 1, II.A.1.).

14.1.1 An EPA Reference Method 9 opacity observation shall be performed on this engine at least once per calendar year of operation when the engine is operating during conditions suitable for properly performing a valid Method 9 observation. If an engine has not been operated or if a valid Method 9 observation could not be performed when the engine did operate during the calendar year, the Source is not required to operate the engine for the sole purpose of obtaining an annual opacity observation.

14.1.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.1.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.1.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observation. These records and the copy of the certification shall be made available to the Division for review upon request.

Annual EPA Method 9 Visible Emissions Observations were performed on each of the engines by a certified observed as indicated in the table below. Annual EPA Method 9 Visible Emissions Observations were conduct on the Fire Pump Engine and the Unit 3 Emergency Diesel Generator during the 2024 calendar year and results are summarized in the table below. Tri-State reported that Tri-State reported that the Fire Pump Engine and the Unit 3 Emergency Diesel Generator operated minimally during the 2024 calendar year with 8.4 hours and 2.5 hours of operation respectively. The Units 1 and 2 Emergency Diesel Generator was reported to have not operated from April 2021 through the date of the inspection on March 25, 2025 due to a mechanical issue.

Engine	Method 9 Reading Date	Observed Opacity (%)
Fire Pump	8/14/2024	0
Units 1 & 2 Emergency Diesel Generator	NA	NA
Unit 3 Emergency Diesel Generator	8/14/2024	1.46

Source is in compliance with this condition.

14.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any pollutant resulting from start-up, which is in excess of 30% opacity for a period or period aggregated more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, II.A.4.).

14.2.1 A record shall be kept of the type, date, and time of the commencement and completion of each and every condition subject to Regulation No. 1, II.A.4. that results in an opacity exceedance. The records shall be made available to the Division upon request for review. A Method 9 observation shall be performed any time an engine start-up requires longer than ten (10) consecutive minutes.

14.2.2 If any of the Method 9 opacity observations exceed the applicable standard, additional observations must be performed. Consecutive observations shall be performed until two (2) consecutive observations are in compliance with the standard. The first additional observation and each successive observation shall be performed no later than sixty (60) minutes after the completion of the previous observation.

14.2.3 Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit, until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

14.2.4 All Method 9 observations shall be performed by a certified observer. A clear, readable copy of the opacity observer's certification shall be kept with the records of the Method 9 observations. The records and the copy of the certification shall be made available for to the Division upon request for review.

Tri-State reported that no engine startup events exceeded ten (10) minutes in duration during the inspection period. No EPA Method 9 Visible Emissions Observations were required under this condition during the inspection period.

Source is in compliance with this condition.

14.3 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [Federal-only requirement]

The emergency diesel fire pump engine in the insignificant activities list is subject to the requirements in 40 CFR Part 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines."

The requirements below reflect the current rule language as of the revisions to 40 CFR Part 63, Subpart ZZZZ published in the Federal Register on 2/27/2014. However, if revisions to this Subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63, Subpart ZZZZ.

The D.C. Circuit Court issued a mandate on May 4, 2016 for vacatur for certain requirements of allowing emergency engines to operate for limited hours for demand response. See EPA memorandum "Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines" published on April 15, 2016 for more information.

These requirements have not been adopted into Colorado Regulation no. 8, Part E as of the date of publication of this Operating Permit, and are therefore not state-enforceable. In the event that these requirements are adopted into Colorado Regulations, they will become state-enforceable.

14.3.1 Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions do not have to meet the requirements of Subpart ZZZ and of 40 CFR Part 63, Subpart A, including initial notification requirements (40 CFR Part 63, §63.6590(b)(3)(iv)). Under Subpart ZZZZ, the definition of a limited use stationary RICE means any stationary RICE that operates less than 100 hours per year (40 CFR Part 63, §63.6675). *Note that the Units 1&2, and the Unit 3 emergency engines may qualify for this*

exemption. The Source must maintain records which demonstrate that the annual hours of operation for each engine are under 100 if claiming this exemption.

§63.6602 – What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

14.3.2 If you own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations and other requirements in Table 2c to this subpart which apply to you (40 CFR Part 63, §63.6602). The applicable requirements of Table 2c are as follows:

14.3.2.1 Change oil and filter every 500 hours of operation or annually, whichever comes first. The Source has the option to utilize an oil analysis program as described in §63.6625(i) to extend the specified oil change requirement.

14.3.2.2 Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary.

14.3.2.3 Inspect all hoses and belts every 500 hours of operation, or annually, whichever comes first, and replace as necessary.

14.3.2.4 During periods of startup the Source must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

§63.6605 – What are my general requirements for complying with this Subpart?

14.3.3 The Source shall be in compliance with the operating limitations and other requirements in Subpart ZZZZ that apply at all times (40 CFR Part 63, §63.6605(a)).

14.3.4 At all times the Source shall operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require the Source to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspections of the Source (40 CFR Part 63, §63.6605(b)).

§63.6625 – What are my monitoring, installation, collection, operation, and maintenance requirements?

14.3.5 The Source shall operate and maintain the engines according to the manufacturer's emission-related written instructions. Alternatively the Source shall develop a separate maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, §63.6625(e)(2)).

14.3.6 The Source shall install a non-resettable hour meter on each engine if not already installed (40 CFR Part 63, §63.6625(f)).

§63.6640 – How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?

14.3.7 The Source shall demonstrate continuous compliance with each operating limitation, and other requirements in Tables 1a, 1b, 2a, 2b, 2c, and 2d of Subpart ZZZZ, as applicable, according to methods specified in Table 6 of Subpart ZZZZ, which are described as follows (40 CFR Part 63, §63.6640(a)):

14.3.7.1 For demonstrating compliance with work or management practices (40 CFR Part 63, Table 6, (9)(a)):

a. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions (40 CFR Part 63, Table 6, (9)(a)(i)); or

b. Develop and follow an alternative maintenance plan which must provide to the extent practicable for the maintenance and operation to the engine in a manner consistent with good air pollution control practice for minimizing emissions (40 CFR Part 63, Table 6, (9)(a)(ii)).

14.3.8 The Source shall operate the engine according to the requirements in §63.6640(f)(1) through (4) (Conditions 14.3.8.1 through 14.3.8.2) for the engine to be considered emergency engine under Subpart ZZZZ. Any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in §63.6640(f)(1) through (4), is prohibited. If the Source does not operate the engine according to the requirements in §63.6640(f)(1) through (4), the engine will not be considered an emergency engine under Subpart ZZZZ and must meet all requirements for non-emergency engines (40 CFR Part 63, §63.6640(f)).

14.3.8.1 There is no time limit on the use of emergency stationary RICE in emergency situations (40 CFR Part 63, §63.6640(f)(1)).

14.3.8.2 The Source may operate the engine for the purposes specified in §63.6640(f)(2)(i) (Condition 14.3.8.2.a) for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by §63.6640(f)(3) and (4) counts as part of the 100 hours per calendar year allowed by §63.6640(f)(2) (40 CFR Part 63, §63.6640(f)(2)).

a. Emergency stationary RICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year (40 CFR Part 63, §63.6640(f)(2)(i)).

§63.6655 – What records must I keep?

14.3.9 The Source shall keep records of the maintenance conducted on the engine to demonstrate that it was operated and maintained according to the maintenance plan (40 CFR Part 63, §63.6655(e)).

14.3.10 The Source shall keep records of the hours of operation of the engine as recorded on the non-resettable hour meter. The owner or operator shall document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation (40 CFR Part 63, §63.6655(f)).

§63.6660 – In what form and how long must I keep my records?

14.3.11 The records shall be in a form suitable and readily available for expeditious review according to §63.10(b)(1) (40 CFR Part 63, §63.6660(a)).

14.3.12 As specified in §63.10(b)(1), the Source shall keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record (40 CFR Part 63, §63.6660(b)).

14.3.13 The Source shall keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1) (40 CFR Part 63, §63.6660(c)).

§63.6665 – What parts of the General Provisions apply to me?

14.3.14 The engine is subject to the General Provisions of 40 CFR Part 63, Subpart A as are outlined in Table 8 of Subpart ZZZZ. These requirements include but are not limited to (40 CFR Part 63, §63.6665):

14.3.14.1 No owner or operator must operate any affected source in violation of the requirements of 40 CFR Part 63 (§63.4(a)(1)); and

14.3.14.2 No owner or operator shall fail to keep records, notify, report, or revise reports as required under 40 CFR Part 63 (§63.4(a)(2)).

Tri-State Craig is an Area Source for emissions of Hazardous Air Pollutants. The State of Colorado has not adopted the Area Source Provisions of MACT Subpart ZZZZ.

15. Colorado Regulation No. 1, Section II – Opacity

These limits apply to the following emission units which reference this condition throughout the Operating Permit:

P101 – Coal Handling System for Units 1 & 2, not including fugitive sources (F101a, F101b, F101c, F101i, and F101j) (Condition 6)

P102 – Coal Handling System for Unit 3, not including fugitive sources (F102a, F102f, F102g, and F102l) (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, not including fugitive sources (F201a) (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, not including fugitive sources (F202a) (Condition 9)

P203 – Ash Handling System for Units 1&2, not including fugitive sources (F203c) (Condition 10)

P204 – Ash Handling System for Unit 3, not including fugitive sources (F204b and F204d) (Condition 11)

S401 & S402 – Units 1 & 2 Cooling Towers, compliance is presumed per Condition 12.5.1 (Condition 12)

S403 – Unit 3 Cooling Tower, compliance is presumed per Condition 13.5.1 (Condition 13)

15.1 Except as provided in Condition 15.2, no owner or operator of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity. This standard is based on 24 consecutive opacity readings taken at 15-second intervals for six minutes. The approved reference method for visible emissions measurements on which these standards are based is EPA Method 9 (40 CFR Part 60, Appendix A (July. 1992)). (Colorado Regulation No. 1, Section II.A.1) Note: This opacity limit applies at all times including during periods of shutdown and to offline emissions except as specified in Condition 15.2.

The facility was operating at the time of the inspection. No visible emissions were observed during the inspection.

Source is in compliance with this condition.

15.2 No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, any process modification, or adjustment or occasional cleaning of control equipment, which is in excess of 30% opacity as measured by EPA Method 9 (unless otherwise specified in this permit) for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes. (Colorado Regulation No. 1, II.A.4)

The facility was operating at the time of the inspection. No visible emissions were observed during the inspection.

Source is in compliance with this condition.

15.3 Unless specific conditions in this permit require otherwise, monitoring for sources subject to Condition 15 shall be performed as follows.

15.3.1 A U.S. EPA Reference Method 9 visual opacity observation (in accordance with 40 CFR Part 60, Appendix A, as adopted by reference in Colorado Regulation No. 6, Part A) shall be performed at least semiannually. If any such observation indicates an exceedance of the

applicable limit, additional observations must be performed. Subject to the provisions of C.R.S. 25-7-123.1 and in the absence of credible evidence to the contrary, exceedance of the limit shall be considered to exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken the shows the opacity is less than the opacity limit. All Method 9 readings shall be conducted by a certified observer.

15.3.2 Records of the results of U.S. EPA Reference Method 9 readings and a copy of the U.S. EPA Reference Method 9 reader's certification shall be kept on site and made available to the Division for inspection upon request.

15.3.3 Copies of any observations exceeding the applicable standard(s) shall be submitted with the next scheduled semi-annual report.

15.3.4 At all other times, in the absence of credible evidence to the contrary, compliance with the opacity limits shall be assumed, provided the Operating and Maintenance Plan requirements for bagfilters / baghouses set forth in Condition 16 are met, as appropriate.

Semi-annual EPA Method 9 Visible Emissions Observations were conducted as required by certified observers. Records were provide and included in the tables below. A review of records provided indicates that Tri-State has not exceeded the opacity limits above. Maintenance records were provided and indicate that the baghouses are operated and maintained consistent with operating and maintenance procedures for the facility.

Tri-State G&T Craig Station P101 Units 1 and 2 Coal Handing System					
Stack ID	**Description**	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/2024	
		Date	Opacity (%)	Date	Opacity (%)
S101d	Primary coal crushing – Units 1 & 2	5/23/2024	0	9/26/2024	10.6
S101e	Secondary coal crushing building – Units 1 & 2	NA(1)	NA(1)	NA(1)	NA(1)
S101f	Common coal transfer building belt A	5/23/2024	0	7/25/2024	0
S101g	Common coal transfer building belt B	6/26/2024	0	7/25/2024	0
S101h	Coal stackout building – Units 1 & 2	5/23/2024	0	7/25/2024	0
S101k	Coal reclaim A – Units 1 & 2	6/10/2024	0	11/21/2024	0
S101l	Coal reclaim B – Units 1 & 2	6/26/2024	0	12/12/2024	0
S101m	Coal tripper deck & silos – Units 1 & 2	5/23/2024	0	12/12/2024	0

(1) Tri-State reported that the S101e Units 1 and 2 Secondary Coal Crushing Building Dust Collector caught fire in April 2023 and the unit has been off-line since that time.

Tri-State G&T Craig Station P102 Unit 3 Coal Handing System					
Stack ID	**Description**	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/20234	
		Date	Opacity (%)	Date	Opacity (%)
S102b	Coal conveyor portal building – Unit 3	1/24/2024	0	8/28/2024	0
S102c	Coal conveyor portal building – Unit 3	1/24/2024	0	8/28/2024	0

Tri-State G&T Craig Station P102 Unit 3 Coal Handing System (Continued)

Stack ID	Description	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/2024	
		Date	Opacity (%)	Date	Opacity (%)
S102d	Secondary coal crushing (2 crushers) – Unit 3	3/7/2024	0	7/25/2024	0
S102e	Coal stackout building – Unit 3	3/7/2024	0	7/25/2024	0
S102h	Coal reclaim system – Unit 3	3/7/2024	0	7/25/2024	0
S102i	Coal tripper deck & silos – Unit 3	3/7/2024	0	8/8/2024	0
S102j	Loadout coal to railcars – Unit 3	NA(1)	NA(1)	NA(1)	NA(1)
S102k	Common coal transfer building extension	5/23/2024	0	7/25/2024	0

(1) Tri-State reported that this emission point did not operate during the monitoring period.

Tri-State G&T Craig Station P201 Units 1 and 2 Lime Handing and Storage Facility					
Stack ID	Description	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/2024	
		Date	Opacity (%)	Date	Opacity (%)
S201b	Limestone truck unloading	6/27/2024	0	7/30/2024	0
S201c	Limestone silo #1 – Units 1 & 2	6/27/2024	0	7/30/2024	0
S201d	Limestone silo #2 – Units 1 & 2	6/27/2024	0	7/30/2024	0

Tri-State G&T Craig Station P202 Unit 3 Lime Handing And Storage Facility					
Stack ID	Description	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/2024	
		Date	Opacity (%)	Date	Opacity (%)
S202b	Lime unloading	6/27/2024	0	12/5/2024	0
S202c	Lime conveying and silo	6/27/2024	0	12/5/2024	0
S202d	Lime day bin	3/6/2024	0	18/28/2024	0

Tri-State G&T Craig Station P203 Units 1 and 2 Ash Handing System					
Stack ID	Description	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/2024	
		Date	Opacity (%)	Date	Opacity (%)
S203a	Ash storage silo A – Units 1 & 2	5/14/2024	0	8/28/2024	0
S203b	Ash storage silo B – Units 1 & 2	3/6/2024	0	7/30/2024	0
S203d	Silo B dry ash unloading – Units 1 & 2	3/6/2024	0	7/30/2024	0
S203e	Silo A dry ash unloading – Units 1 & 2	5/14/2024	0	8/28/2024	0

Tri-State G&T Craig Station P204 Unit 3 Ash Handing System					
Stack ID	Description	1/1/2024 – 6/30/2024		7/1/2024 – 12/31/2024	
		Date	Opacity (%)	Date	Opacity (%)
S204a	Ash storage silo C – Unit 3	5/14/2024	0	8/28/2024	0
S204c	Recycle ash tank	3/6/2024	0	8/28/2024	0

Tri-State reported that S101k - Units 1 and 2 Coal Reclaim A Dust Collector was taken out of service in March 2023 as the result of a part failure and has not returned to service. The S102j Loadout coal to railcars – Unit 3 did not operate in 2024. Because these units did not operate in 2024, Method 9 readings were not required for the semi-annual periods of January 1, 2024 through June 30, 2024 and July 1, 2024 through December 31, 2024.

Source is in compliance with this condition.

16. Periodic Monitoring and Operating and Maintenance (O&M) Requirements for Control Devices

These requirements apply to each bagfilter / baghouse and scrubber associated with the following emission units which vent to the control device/s, as appropriate (Colorado Regulation No. 3, Part C, Section V.C.5.):

B001 – Unit 1 Boiler, baghouse and scrubber (Condition 1)

B002 – Unit 2 Boiler, baghouse and scrubber (Condition 2)

B003 – Unit 3 Boiler, baghouse and scrubber (Condition 3)

P101 – Coal Handling System for Units 1 & 2, baghouse (Condition 6)

P102 – Coal Handling System for Unit 3, baghouse (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2, baghouse (Condition 8)

P202 – Lime Handling and Storage Facility for Unit 3, baghouse (Condition 9)

P203 – Ash Handling System for Units 1&2, baghouse (Condition 10)

P204 – Ash Handling System for Unit 3, baghouse (Condition 11)

16.1 Bagfilters / Baghouses

16.1.1 The baghouse shall be equipped with an operable pressure drop measuring device. Pressure drop and/or cycle-time set point shall be used as a parameter for initiating compartment cleaning cycles. Documentation of the manufacturer's recommended operating range shall be maintained and made available to the Division for inspection upon request. Readings that are outside the range shall be cause for investigation. The results of any related maintenance work performed shall be documented in either hardcopy or electronic form and made available to the Division for inspection upon request.

16.1.2 Routine maintenance of and operational procedures performed on the baghouse shall be conducted in accordance with manufacturer's specifications and good engineering practices. These procedures shall be in written format. Any maintenance work performed shall be documented and made available to the Division for inspection upon request.

16.1.3 The baghouse shall be periodically inspected for bag integrity and overall mechanical integrity. At a minimum, these checks will be performed whenever the unit is down for a Planned Maintenance Outage (PMO). In addition, an inspection and any necessary maintenance or repairs shall be made whenever an opacity spike is observed, or if there is reason to suspect a broken bag or other equipment malfunction. For purposes of this requirement, a "spike" is defined as a sudden or gradual increase in opacity that, based on the operator's experience, may indicate a possible control equipment of process problem. Repairs performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of these inspections, shall be documented and made available to the Division for inspection upon request.

16.1.4 [Unit 3 Baghouse Only] The bag leak detector will be operated and maintained in accordance with manufacturer's recommendations and good engineering practices. In the event that the leak detector indicates a leak, the Source will make the necessary repairs to the baghouse as soon as safely practicable. Leaks and their associated repairs will be documented for Division inspection upon request.

16.1.5 All records associated with baghouse O&M requirements must be retained for a minimum of five years.

Each baghouse compartment is monitored continuously for pressure changes and leaks. Compliance with opacity limits is monitored using COMS. The Unit 3 baghouse is equipped with a bag leak detection system as required. The bag leak detection system is operated and maintained in accordance with the manufacture's recommendations and good engineering practices as required. When a spike in opacity is discovered, faulty baghouse compartments are isolated for further inspection by plant personnel. Bags are replaced when necessary by plant personnel. No exceedances of visible emissions limits were reported during the inspection period. No visible emissions were observed during the inspection.

Source is in compliance with this condition.

16.2 Scrubbers

16.2.1 The Source shall perform routine maintenance and inspections of the equipment. The routine maintenance will be based upon operating hours of the scrubber equipment. Repairs or adjustments performed (other than minor adjustments) as a result of these inspections, as well as any repairs done as a result of these inspections, shall be documented and made available to the Division for inspection upon request.

16.2.2 SO_2 readings from the CEMS will be used as an indicator of maintenance needs or operational changes to the scrubber. Repairs or adjustments performed (other than minor adjustments), as well as any repairs done as a result the SO_2 readings, shall be documented and made available to the Division for inspection upon request.

16.2.3 All records associated with scrubber O&M requirements must be retained for a minimum of five years.

Scrubber maintenance is performed as needed. Compliance with SO_2 limits is monitored using SO_2 CEMS certified to 40 CFR 75 requirements as required. Removal efficiencies are monitored continuously based on coal sampling and outlet monitoring as required. Tri-State reported no exceedances of SO_2 emissions limits during the inspection period.

Source is in compliance with this condition.

17. Particulate Matter Stack Testing

These requirements apply to each PM emission unit in this permit which has been identified as requiring stack testing to demonstrate compliance with an applicable PM emission limit, as appropriate.

17.1 To demonstrate compliance with 40 CFR Part 60, Subpart Da PM emission limits, subsequent performance testing on Unit 3 for filterable PM emissions must be performed within 12 months of the previous performance test in accordance with the schedule outlined in §60.48Da(o), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.2 To demonstrate compliance with 40 CFR Part 63, Subpart UUUUU (MATS) and Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent MATS and Regional Haze performance testing on Units 1 and 2, and subsequent MATS performance testing on Unit 3 for filterable PM emission limits must be performed in accordance with the schedule specified under MATS, in accordance with the requirements of Conditions 1.1, 1.10, 2.1, 2.9.3, 3.1, 3.10, and 5, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3 To demonstrate compliance with the Best Available Control Technology (BACT) PM and PM_{10} filterable and condensable emission limits for Unit 3, performance testing must be performed annually (Colorado Construction Permit 12MF322-1), in accordance with the requirements of Condition 3.1, as appropriate. Performance tests must be performed using Division-approved methods as set forth in 40 CFR Part 60, Appendix A, and Colorado Regulation No. 1, Section III.A.2.

17.3.1 If the results of the performance testing show that the PM and PM_{10} filterable and condensable emissions are less than 75% of the BACT limits, the next performance testing may be performed biennially instead of annually.

17.4 To demonstrate compliance with Colorado Regulation No. 23, Regional Haze PM emission limits, subsequent performance testing on Unit 3 for filterable PM and PM_{10} emissions must be performed in accordance with the requirements and procedures set forth in EPA Test Method 5, and Method 201A, as set forth in 40 CFR Part 60, Appendix A. This performance testing must be performed annually, or in accordance with the following schedule, as applicable:

17.4.1 If any test results indicate emissions are less than or equal to 50% of the emission limit, the subsequent test shall be performed within five (5) years of the date of the test.

17.4.2 If any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, the subsequent test shall be performed within three (3) years of the date of the test.

17.4.3 If any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until either of the above test results are achieved. A performance test must consist of three (3) test runs, with each run at least 120 minutes in duration. Test results must be converted to the applicable units and compliance with be based on the average of three (3) test runs.

17.5 For all compliance demonstrations in Condition 17:

17.5.1 The test protocol, test, and test report shall be in accordance with the requirements of the APCD Compliance Test Manual (https://www.colorado.gov/pacific/cdphe/air/compliance-

enforcement). A compliance testing protocol shall be submitted for Division approval at least thirty (30) calendar days prior to any performance of the test required under this condition.

17.5.2 No compliance test required herein shall be performed without prior written approval of the protocol by the Division.

17.5.3 The Division reserves the right to witness the test. In order to facilitate the Division's ability to make plans to witness the test, notice of the date (s) for the stack test shall be submitted to the Division at least thirty (30) calendar days prior to the test.

17.5.4 The Division may for good cause shown, waive this thirty (30) day notice requirement. In instances when a scheduling conflict is presented, the Division shall immediately contact the permittee in order to explore the possibility of making modifications to the stack test schedule.

17.5.5 The compliance test results shall be submitted to the Division within sixty (60) calendar days of the completion of the test unless a longer period is approved by the Division.

17.5.6 Any stack test conducted to show compliance with an annual emission limitation shall multiply the results of the test (lb/MMBtu) by the annual permitted fuel usage to compare against the limitation.

17.5.7 Results of all tests conducted shall be kept on site and made available to the Division upon request.

17.5.8 The performance testing for filterable PM may be satisfied by the periodic PM testing required by 40 CFR Part 63, Subpart UUUUU (MATS) in accordance with the requirements of Condition 5, as appropriate.

PM Testing on Unit 1 was conducted on January 18, 2024 and on Unit 2 on January 18, 2024. The Division reviewed and approved this testing on February 26, 2024. The testing conducted on January 18, 2024 indicated compliance with applicable emissions standards and qualified the two Units as LEE for PM under 40 CFR 63, Subpart UUUUU. PM testing was conducted on Unit 3 on June 15, 2024. The Division reviewed and approved this testing on August 21, 2024. The testing conducted on Unit 3 indicated compliance with applicable emissions standards and qualified the Unit as LEE for PM under 40 CFR 63, Subpart UUUUU. 40 CFR 60, Subpart Da requires that PM testing be conducted annually on Unit 3. PM Testing for 40 CFR 60, Subpart Da was conducted on Unit 3 on June 15, 2024. The Division reviewed and approved this testing on August 21, 2024 indicating passing results. Tri-State submits Test Protocols, and Test Reports within the specified submittal deadlines as required.

Source is in compliance with this condition.

17.6 During each of the Method 5 performance tests conducted on Unit 3 as required by this condition, a baseline opacity limit shall be established for the compliance assurance monitoring (CAM) requirements as specified in Conditions 3.13, and Appendix H. The value of the baseline opacity level is determined by averaging all of the 6-minute average opacity values (reported to the nearest 0.1 percent opacity) from the COMS measurement recorded during each of the test run intervals conducted for the performance test, and then adding an baseline opacity adjustment factor to the calculated average value for all of the test runs.

17.6.1 The baseline opacity adjustment factors are:

17.6.1.1 5.0% opacity addition to the test run opacity average if the results of the PM performance tests are less than or equal to 50% of the PM standard; or

17.6.1.2 3.5% opacity addition to the test run opacity average if the results of the PM

performance test are greater than 50%, but less than or equal to 75% of the PM standard; or

17.6.1.3 2.5% opacity addition to the test run opacity average if the results of the PM performance test are greater than 75% of the PM standard.

17.6.2 If the calculated opacity value (COMS average plus adjustment factor) is less than 5.0%, then the opacity baseline level is set at 5.0%.

17.6.3 If the baseline opacities established under this condition from any subsequent PM performance test are less than the current baseline opacity levels minus 1%, the Source shall maintain the new baseline opacity used as the indicator range on site for Division inspection upon request.

17.6.4 If the baseline opacities established under this condition from any subsequent PM performance test are greater than or equal to the current baseline opacity level minus 1%, the Source shall maintain records of the new baseline opacity used as the indicator range on site and available for Division inspection upon request.

Tri-State established a baseline opacity of 6.4% for CAM monitoring during PM Testing conducted on June 15, 2024. Tri-State reported that no CAM excursions of the established CAM opacity limits occurred during the inspection period.

Source is in compliance with this condition.

18. 40 CFR Part 60, Subpart A, General Provisions for New Source Performance Standards

Units subject to an NSPS under 40 CFR Part 60 are subject to the requirements under Subpart A, General Provisions, which include but are not limited to:

B001 – Unit 1 Boiler (Condition 1)

B002 – Unit 2 Boiler (Condition 2)

B003 – Unit 3 Boiler (Condition 3)

P101 – Coal Handling System for Units 1 & 2 – S101d, S101e, S101f, and S101g (Condition 6)

P102 – Coal Handling System for Unit 3 – F102a, S102b, S102c, S102d, S102h, S102j, S102k, and S102l (Condition 7)

P201 – Limestone Handling and Storage Facility for Units 1 and 2 – limestone belt conveyors (Condition 8)

18.1 At all times, including periods of startup, shutdown, and malfunction owners and operators shall to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source (40 CFR Part 60.11(d), as adopted by reference in Colorado Regulation No. 6, Part A).

18.2 The Source shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the affected facility; or any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or device is inoperative (40 CFR Part 60, §60.7(b), as adopted by reference in Colorado Regulation No. 6, Part A).

18.3 No article, machine, equipment or process shall be used to conceal an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gasses discharged into the atmosphere (40 CFR Part 60, §60.12, as adopted by reference in Colorado Regulation No. 6, Part A).

Tri-State maintains records of startup, shutdown and malfunction for the subject equipment as required. Tri-State submits quarterly Excess Emissions Reports (EERs) that included all emissions monitor downtime and any excess emissions. No evidence was observed or discovered during the inspection to indicate that the subject equipment is no operated and maintained in a manner consistent with good air pollution control practices for minimizing emissions. No evidence was observed or discovered during the inspection to indicate that Tri-State was attempting to conceal emissions.

Source is in compliance with this condition.

19. Continuous Opacity Monitoring Systems (COMS) and Continuous Emissions Monitoring Systems (CEMS)

The following requirements apply to the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow continuous emission monitoring systems (CEMS), and to the continuous opacity monitoring systems (COMS). Note that these requirements are in addition to those under the Acid Rain Program as set forth in Section III of this permit, those under 40 CFR Part 60, Subparts D and Da – Standards of Performance for Electric Utility Steam Generating Units, those under 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, and those under the Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001).

19.1 CEMS and COMS Quality Assurance and Quality Control (QA/QC) Requirements

19.1.1 Except as provided for below, the Unit 3 CO CEMS is subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation and performance specifications of 40 CFR Part 60 Appendix B, Performance Specification 4/4A. This CEMS are subject to the quality assurance/quality control requirements in 40 CFR Part 60, Appendix F and Subpart A, §60.13 and Condition 19.1.8 of this permit.

19.1.1.1 The CO data shall meet the applicable "primary equipment hourly operating requirements" for hourly average calculation methodology specified in 40 CFR Part 75, Subpart B, §75.10(d).

19.1.1.2 Relative accuracy test audit (RATA) frequency will be determined according to 40 CFR Part 60, Appendix F.

19.1.2 The SO_2, NO_x (and diluent), CO_2, and flow monitors are subject to the applicable requirements of 40 CFR Part 75. The monitoring systems shall meet the equipment, installation, and performance specification requirements in 40 CFR Part 75, Appendix A. These CEMS shall meet the QA/QC requirements in 40 CFR Part 75, Appendix B and the conversion procedures of Appendix F and Condition 19.1.8 of this permit.

19.1.3 The Unit 3 stack inlet SO_2 and CO_2 monitors are subject to the applicable requirements of 40 CFR Part 60. The monitoring systems shall meet the equipment, installation, and performance specifications in 40 CFR Part 60, Appendix B, the QA/QC requirements in 40 CFR Part 60, Appendix F, and the conversion procedures of Condition 19.1.8.

19.1.4 The COMS are subject to the requirements of 40 CFR Part 75. Each COMS shall meet the design, installation, equipment, and performance specifications in 40 CFR Part 60, Appendix B, Performance Specification 1.

19.1.5 QA/QC plans shall be prepared for the NO_x (including diluents: CO_2 or O_2), SO_2, CO_2, CO (Unit 3 only), and volumetric flow CEMS in accordance with the requirements of 40 CFR Part 75, Appendix B. These plans shall be made available to the Division upon request. Revisions shall be made to the plans at the request of the Division.

19.1.6 [Units 1 & 2 COMS] The Source must follow the QA/QC procedures of 40 CFR Part 60, Subpart A, §60.13(d), and Subpart D, §60.45(c)(3).

19.1.7 **[Unit 3 COMS]** The Source shall follow the QA/QC requirements of 40 CFR Part 60, Subpart A, §60.13(d) and Subpart Da, §60.48Da(o)(2)(ii).

19.1.8 The SO_2, NO_x, and CO CEMS are subject to the following requirements:

19.1.8.1 [Relative Accuracy Test Audits (RATA)] RATA shall be conducted in the units of

the emission limitation (e.g., lb/MMBtu) for all of the emission limitations that are applicable to the emissions unit. The RATA for emissions units that have annual emission limitations (tons/yr) will be conducted in terms of pounds per hour (lb/hr).

19.1.8.2 [Data Acquisition and Handling System (DAHS)**]** The DAHS shall be able to record and manipulate the data in the units of the emission limitation (e.g., lb/MMBtu) and meet the reporting requirements for all of the emissions limitations that are applicable to the emissions unit.

Note at the time of issuance of this permit, the Source has installed and certified the CEMS required under this condition.

Each unit is equipped with all the required monitoring equipment. The monitoring systems are operated and maintained as required, and all Quality Assurance and Quality Control requirements under 40 CFR Part 60. 40 CFR Part 63, and 40 CFR Part 74 are implemented as required. The DAHS is capable of reporting and manipulating data to allow for evaluating compliance with all applicable standards for the facility.

Source is in compliance with this condition.

19.2 General Provisions

19.2.1 The Source shall ensure that all CEMS and COMS required are in operation and monitoring unit emissions or opacity at all times that the associated boiler combusts any fuel, except as follows:

19.2.1.1 During gaseous fuel combustion provided special considerations are met as provided in 40 CFR Part 75, §75.11(e);

19.2.1.2 During the use of an alternative monitoring system as approved by the Administrator pursuant to the requirements in 40 CFR Part 75, Subpart E (see Condition 19.2.2);

19.2.1.3 During periods of calibration, quality assurance, or preventative maintenance performed pursuant to 40 CFR part 75, §75.21 and Appendix B;

19.2.1.4 During periods of repair, periods of backups of data from a data acquisition and handling system or recertification performed pursuant to 40 CFR Part 75, §75.20;

19.2.1.5 The Source shall also ensure, subject to the exceptions noted above, that the COMS required are in operation and monitoring opacity during the time following combustion when fans are still operating, unless fan operation is not required to be included under any other applicable requirement (40 CFR Part 75, §75.10(d)).

The source monitors unit emissions at all times when fuel is combusted and monitors opacity using COMS at all times when the fans are operating.

Source is in compliance with this condition.

19.2.2 Alternative monitoring system, alternative reference method, or any other alternative for the required CEMS shall not be used without having obtained prior written approval from the appropriate agency, either the Division or the U.S. EPA, depending on which agency is authorized to approve such alternative under applicable law. Any alternative CEMS or COMS shall be certified in accordance with the requirements of 40 CFR Parts 60 or 75, as applicable, prior to use.

19.2.3 All test and monitoring equipment, methods, procedures, and reporting shall be subject to the review and approval by the Division, prior to any official use. The Division shall have the right

to inspect such equipment, methods, and procedures and data obtained at any time. The Division may provide a witness(es) for any and all tests, at the Division's discretion.

19.2.4 A file shall be maintained of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by applicable portions of 40 CFR Part 60, Subparts A, D, Da, Appendices A, B, and F, and 40 CFR Part 75. This information must be recorded in a permanent form suitable for Division inspection (40 CFR Part 60, §60.7(f)).

19.2.5 Records shall be maintained of the occurrence and duration of any startup, shutdown, or malfunction, or emergency condition (as defined in Subpart Da) in the operation of the source; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative (40 CFR Part 60, §60.7(b)).

The source maintains records of startup, shutdown and malfunction as required. Tri-State supplies quarterly QA/QC checks per 40 CFR Part 60, 40 CFR Part 63, and 40 CFR Part 75 with excess emissions reports. The source reported no alternative monitoring during the inspection period.

Source is in compliance with this condition.

19.3 Data Replacement Requirements

19.3.1 **[CEMS]** For periods when QA data is not available from the CEMS, the data replacement procedures in 40 CFR Part 75, Subpart D shall be used for determining the total (annual) emissions. For purposes of monitoring compliance with the annual NOx and SO_2 emission limitations (tons/yr), replaced and bias-adjusted data shall be included when assessing compliance with the annual limitations.

Note that CO emissions are not specifically referenced in the Subpart D procedures, the CEMS DAHS is programmed to substitute CO emissions using the same procedures specified for NO_x. Additionally, since CO emissions are not subject to requirements in 40 CFR Part 75, the CO emission data is not required to be bias-adjusted.

19.3.2 [COMS] When the COMS is unable to provide QA data in accordance with 40 CFR Part 75 for more than eight (8) consecutive hours, the Source shall utilize either a backup opacity monitor, EPA Reference Method 9, or an "Operating Report During Monitor Unavailability" to satisfy the requirements for periodic monitoring under 40 CFR Part 70 and Colorado Regulation No. 3.

19.3.2.1 If backup monitors are used, the next quarterly report submitted by the Source shall identify the dates and times the backup monitors were in use.

19.3.2.2 If EPA Reference Method 9 observations are used, visual observations in accordance with the reference method shall be taken and recorded by the Source whenever the Source is in operation and while fuel is present in the boiler.

a. When such circumstances exist, the visual observations shall be performed by a certified opacity observer each 24 hour period thereafter over a thirty minute period until the opacity monitoring system is again able to provide QA data.

b. If a visual emissions observation cannot be performed in accordance with EPA Reference Method 9, the Source shall record the reasons why that is the case.

c. Subject to the provisions of C.R.S. 25-7-123.1, and in the absence of credible evidence to the contrary, exceedance of the opacity limit shall be considered to

exist from the time a Method 9 reading is taken that shows an exceedance of the opacity limit until a Method 9 reading is taken that shows the opacity is less than the opacity limit.

19.3.2.3 If an "Operating Report During Monitor Unavailability" is used, the Source shall record the registered opacity monitor reading prior to the monitor unavailability period and that immediately follows such periods. A Source shall also record and maintain a description of a unit operating characteristics that demonstrate the likelihood of compliance with the applicable opacity limitation. Such operating circumstances shall be identified on a unit specific basis and provided to the Division and shall include information related to the operation of the control equipment and any other operational parameters that may affect opacity.

Data substitution procedures are properly implemented in accordance with applicable sections of 40 CFR 75.

Source is in compliance with this condition.

19.4 Recordkeeping and Reporting Requirements

19.4.1 The Source shall submit excess emissions and monitoring reports and/or summary reports as required by 40 CFR Part 60, Subpart A, §60.7(c) and (d). The frequency of submittal of such reports shall be quarterly, and such reports shall be submitted to the Division by the 30th day following the end of each calendar quarter. Reports shall consist of the following information for all pollutants monitored for the quarterly period and all applicable limits of this permit:

19.4.1.1 Excess emission reports shall include the following information:

a. The magnitude of excess emissions computed in accordance with §60.13(h) and Division guidelines, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period (40 CFR Part 60, §60.7(c)(1)).

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunctions (if known), the corrective action take or preventative measures adopted (40 CFR Part 60, §60.7(c)(2)).

c. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks and the nature of the system repairs or adjustments (40 CFR part 60, §60.7(c)(3)).

d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report (40 CFR Part 60, §60.7(c)(4)).

19.4.1.2 The summary report form shall contain the information and be in the format shown in Figure 1 of 40 CFR Part 60, §60.7 unless otherwise specified by the Division. One summary report form shall be submitted for each pollutant monitored at the facility (40 CFR Part 60, §60.7(d)).

a. If the total duration of excess emissions for the reporting period is less than 1 percent (%) of the total operating time for the reporting period, and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) (Condition 19.4.1.1) need not be submitted unless requested by the Division (40 CFR Part 60, §60.7(d)(1)).

b. If the total duration of excess emissions for the reporting period is 1 percent (%) or greater of the total operating time for the reporting period, or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) (Condition 19.4.1.1) shall both be submitted (40 CFR Part 60, §60.7(d)(2)).

The source submits quarterly EERs as required. The facility reported no excess emissions from Unit 1, Unit 2 or Unit 3 during the inspection period. All EERs were received by the Division in a timely manner. See the Reports section above for details regarding those reports.

Source is in compliance with this condition.

19.5 Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001), Units 1 and 2 only

19.5.1 The SO_2 CEMS shall be placed in a location to accurately monitor 100% of the flue gas, including any periods of bypass.

19.5.2 The Source must continuously and accurately monitor and report to the Division, pursuant to Section IX of the SIP component, the hourly average pressure drop across the mist eliminator and the hourly average flow rate for each unit at Units 1 and 2. The Source's pressure monitoring system shall be of sufficient sensitivity and reliability to enable consistent, continuous, and effective monitoring of the pressure drop range. The Source must take all necessary corrective actions to maintain the pressure drop within the applicable range.

19.5.3 The Source must provide to the Division on a quarterly basis all excess emission reports (EERs) for Craig Units 1 and 2 that describe in the form required by Section IX of the July 5, 2001 Colorado State Implementation Plan component, all excess readings, all claimed exemptions, and all other information required by law.

19.5.4 The Source must maintain, calibrate, and operate a method of coal sampling and analysis to determine accurately, pursuant to methods identified in Section 8(b)(viii) of the SIP component (see Condition 20), the potential emissions from sulfur in the coal entering the boiler reported in lb of SO_2 per MMBtu heat input.

19.5.5 The Source shall report to the Division on a quarterly basis each 30 day rolling average and each 90 day rolling average during the prior quarter that exceeded or failed to comply with the SO_2 emission limitations in Conditions 1.2.4 and 2.2.4. Each quarterly report shall include a list of the hours excluded for any reason from the determination of the Source's compliance with the SO_2 limits, and a list of times in which flue gas is bypassed around the FGD.

19.5.6 The Source must calculate hourly average NO_x concentrations in lb/MMBtu, in accordance with the requirements of 40 CFR Part 75. The Source must use the hourly averages to calculate calendar year averages in accordance with the requirements of 40 CFR Part 75.

19.5.7 The Source must report to the Division on a quarterly basis the Source's year-to-date average NO_x emission rate for that calendar year.

19.5.8 For any hour that valid, quality-assured CEMS data for a unit is unavailable, SO_2, NO_x, and CO_2 emissions shall be calculated in accordance with the missing data substitution procedures contained in 40 CFR Part 75 (Condition 19.3). For any day in which daily coal sample data are not available, the average potential SO_2 emission rate of coal from the previous 30 days as calculated in Conditions 1.2.4 and 2.2.4 shall be substituted.

19.5.9 The Source shall be bound by the data from their COMS, SO_2, CEMS and coal sampling data, and NO_x CEMS. The Source may not challenge the accuracy or credibility of their COMS, SO_2 CEMS and coal sampling data, and NO_x CEMS in any enforcement action unless otherwise expressly allowed by statue or regulation.

Tri-State maintains and operates CEMS for NOx, SO2, and CO2 as required. CEMS Data is calculated as required and reported quarterly in Excess Emissions Reports (EERs) as required. Data substitution is conducted consistent with the requirements of 40 CFR Part 75 when appropriate. The pressure drop for the mist eliminator is continuously monitored as required and is equipment with an alarm system that activates should the differential pressure deviated for the established normal range of 0.2 inches water column to 1.0 inches water column. Corrective action is implemented as expeditiously as possible anytime the differential pressure is out of range as required. No instances were reported when the differential pressure was out of range during the inspection period. Coal samples are taken daily and analyzed for ash, heat, and sulfur content daily for each electric generating unit at Craig station.

Source is in compliance with this condition.

20. Coal Sampling

20.1 Coal must be sampled on at least a quarterly basis and must be analyzed to determine the heat content, weight percent sulfur, weight percent ash, and moisture content of the coal. The Source must follow Division approved coal sampling plan as shown in Appendix N (Colorado Regulation No. 3, Part C, Section V.C.5.).

20.2 In the event that more than one coal sampling analysis is performed during a quarter, the results of the analyses shall be averaged to determine quarterly average values for heat content, weight percent sulfur, and weight percent ash in the coal. These average values shall be used for subsequent calculations and demonstrations of compliance.

20.3 Coal sampling will follow the most current version of ASTM D2234, *Standard Practice for Collection of a Gross Sample of Coal*. Sample preparation will follow the most current version of ASTM 2013, *Standard Method of Preparing Coal Samples for Analysis*. Sulfur analysis will follow the most recent version of ASTM D4239, *Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods* (Colorado State Implementation Plan (July 5, 2001, FR35374, effective August 6, 2001)).

20.4 In lieu of sampling under Condition 20.1, 20.2, and 20.3, vendor receipts, invoices, contracts, or other information may be used to provide the values for sulfur, ash, moisture, and heat content. Such alternative information shall indicate that coal sampling and analyses have been performed in accordance with the ASTM procedures, or equivalent, as identified in Condition 20.3.

20.5 Records of all coal analyses and vendor provided information must be maintained for Division inspection upon request.

Coal samples are taken daily and analyzed for ash, heat, and sulfur content daily for each electric generating unit at Craig station.

Source is in compliance with this condition.

21. Emission Factors

The Source shall comply with the provisions of Regulation No. 3 concerning APEN reporting. Except as provided for below, emission factors and/or other emission estimating methods that are specified within this permit cannot be adjusted without requiring a permit modification. Emission factors and/or other emission estimating methods used only to comply with the reporting requirements of Colorado Regulation No. 3, Part A, Section II can be updated and modified as specified in that Section. These changes by themselves do not require any permitting activities though the resulting emission estimate may trigger permitting activities.

Tri-State calculates emissions using the specified emissions calculation methodologies consistent with the requirements of operating Permit 96OPMF155. APENS are submitted as required (see APEN Section).

Source is in compliance with this condition.

22. Compliance Assurance Monitoring (CAM) Requirements

The CAM requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, apply to Units 1 (PM, SO_2), 2 (PM, SO_2, NO_x), and 3 (PM/PM_{10}, SO_2, NO_x), and to S102d, secondary coal crushing building (PM), as follows.

22.1 For Units 1 and 2 with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix G. Excursions, for purposes of reporting are as follows:

22.1.1 An opacity value greater than 15.0% occurring for 6 minutes or more.

Tri-State conducts CAM monitoring as required. CAM excursions were appropriately reported with respect to the 15% 6 minute average opacity requirement from Unit 1 and Unit 2 and were addressed consistent with the requirements of Appendix G.

Source is in compliance with this condition.

22.2 For Units 1 and 2 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix J. Excursions, for purposes of reporting are as follows:

22.2.1 Any 30-day average of SO_2 emissions that exceed 0.11 lb/MMBtu.

Tri-State conducts CAM monitoring as required. No CAM excursions were reported with respect to the 30-day average SO2 limit of 0.11 lb/MMBtu for Unit 1 and Unit 2.

Source is in compliance with this condition.

22.3 For Unit 2 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix **Error! Reference source not found.**. Excursions, for purposes of reporting are as follows:

22.3.1 Any 30-day average of NO_x emissions that exceed 0.08 lb/MMBtu.

Tri-State conducts CAM monitoring as required. No CAM excursions were reported with respect to the 30-day average NOx emissions limit of 0.08 lb/MMBtu for Unit 2.

Source is in compliance with this condition.

22.4 For Unit 3 with respect to emissions of PM/PM_{10}, the Source shall follow the CAM plan provided in Appendix H. Excursions, for purposes of reporting are as follows:

22.4.1 An opacity value greater than 7.5% occurring for 6 minutes or more; or

22.4.2 Any 24-hour period in which the average opacity exceeds the baseline level established as required by Condition 17.6.

Tri-State Conducts CAM monitoring as required. CAM excursions were appropriately reported with respect to the 7.5% 6 minute average opacity requirement and addressed consistent with the requirements of Appendix H.

No CAM excursions with regard to Condition 17.6 24-hour established baseline level opacity for Unit 3 occurred during the inspection period.

Source is in compliance with this condition.

22.5 For Unit 3 with respect to emissions of SO_2, the Source shall follow the CAM plan provided in Appendix K. Exceedances, for the purposes of reporting are as follows:

22.5.1 Any 30-day average of SO_2 emissions that exceed 0.15 lb/MMBtu; or

22.5.2 Any daily average of SO_2 emissions that exceeds 0.20 lb/MMBtu.

Tri-State conducts CAM monitoring as required. No CAM excursions were reported with respect to the 30-day average SO2 limit of 0.15 lb/MMBtu or the daily average SO2 limit of 0.20 lb/MMBtu.

Source is in compliance with this condition.

22.6 For Unit 3 with respect to emissions of NO_x, the Source shall follow the CAM plan provided in Appendix M. Exceedances, for the purposes of reporting are as follows:

22.6.1 Any 30-day average of NO_x emissions that exceed 0.28 lb/MMBtu.

Tri-State conducts CAM monitoring as required. No CAM excursions were reported with respect to the 30-day average NOx emissions limit of 0.28 lb/MMBtu for Unit 3.

Source is in compliance with this condition.

22.7 For S102d with respect to emissions of PM, the Source shall follow the CAM plan provided in Appendix I. Excursions, for purposes of reporting are as follows:

22.7.1 Any visible emissions seen during Method 22 visible emissions observations; or

22.7.2 A pressure differential of less than 5 inches of water, or greater than 8 inches of water.

Tri-State conducts CAM monitoring as required. No CAM excursion were reported for the Unit 3 Secondary Coal Crushing (S102d) with respect to visible emissions observed during Method 22 readings. No CAM excursions with differential pressure outside of the 5 to 8 inches water column range were reported.

Source is in compliance with this condition.

22.8 Excursions and/or exceedances shall be reported as required by Section V, Conditions 21 and 22.d of this permit (Colorado Regulation No. 3, Part C, Section V.C.5.).

Tri-State includes all excursions in Semi-Annual Monitoring and Deviations Reports, and Annual Compliance Certifications as required.

Source is in compliance with this condition.

22.9 Operation of Approved Monitoring

22.9.1 At all times, the owner or operator shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment (40 CFR Part 64, §64.7(b), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.2 Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs,

and required quality assurance or control activities shall not be used for purposes of these CAM requirements, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions (40 CFR Part 64, §64.7(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3 Response to excursions or exceedances

22.9.3.1 Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable (40 CFR Part 64, §64.7(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.3.2 Determination of whether the owner of operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process (40 CFR Part 64, §64.7(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.9.4 After approval of the monitoring required under the CAM requirements, if the owner or operator identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the owner or operator shall promptly notify the Division and, if necessary submit a proposed modification for this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters (40 CFR Part 64, §64.7(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

Tri-State conducts CAM monitoring as required. Excursions were reported during the inspection period. Tri-State reported that when an excursion occurs, appropriate corrective action consistent with the requirement of the CAM provision is implemented as expeditiously as possible. No modifications to the CAM requirement have been required.

Source is in compliance with this condition.

22.10 Quality Improvement Plan (QIP) Requirements

22.10.1 Based on the results of a determination made under the provisions of Condition 22.9.3.2, the Division may require the owner or operator to develop and implement a QIP (40 CFR Part 64, §64.8(a), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.2 The owner or operator shall maintain a written QIP, if required, and have it available for inspection (40 CFR Part 64, §64.8(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3 The QIP initially shall include procedures for evaluating the control performance problems and, based on the results of the evaluation procedures, the owner or operator shall modify the plan to include procedures for conducting one or more of the following actions, as appropriate:

22.10.3.1 Improved preventative maintenance practices (40 CFR Part 64, §64.8(b)(2)(i), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.2 Process operation changes (40 CFR Part 64, §64.8(b)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.3 Appropriate improvements to control methods (40 CFR Part 64, §64.8(b)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.4 Other steps appropriate to correct control performance (40 CFR Part 64, §64.8(b)(2)(iv), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.3.5 More frequent or improved monitoring (only in conjunction with one or more steps under Conditions 22.10.3.1 through 22.10.3.4) (40 CFR Part 64, §64.8(b)(2)(v), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.4 If a QIP is required, the owner or operator shall develop and implement a QIP as expeditiously as practicable and shall notify the Division if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined (40 CFR Part 64, §64.8(c), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.5 Following implementation of a QIP, upon any subsequent determination pursuant to Condition 22.9.3.2, the Division or the U.S. EPA may require that an owner or operator make reasonable changes to the QIP if the QIP is found to have:

22.10.5.1 Failed to address the cause of the control device performance problems (40 CFR Part 64, §64.8(d)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); or

22.10.5.2 Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions (40 CFR Part 64, §64.8(d)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.10.6 Implementation of a QIP shall not excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act (40 CFR Part 64, §64.8(e), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

A QIP has not been required by the Division.

Source is in compliance with this condition.

22.11 Reporting and Recordkeeping Requirements

22.11.1 Reporting Requirements: The reports required by Section V, Condition 22.d, shall contain the information specified in Appendix B of the permit and the following information, as applicable:

22.11.1.1 Summary information on the number, duration and cause (including unknown cause, if applicable), for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable) (40 CFR Part 64, §64.9(a)(2)(ii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV); and

22.11.1.2 The owner or operator shall submit, if necessary, a description of the actions taken to implement a QIP during the reporting period as specified in Condition 22.10 of this permit. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring (40 CFR Part 64 § 64.9(a)(2)(iii), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2 General Recordkeeping Requirements: In addition to the recordkeeping requirements in Section V, Condition 22.a through c.

22.11.2.1 The owner or operator shall maintain records of any written QIP required pursuant to Condition 22.10 and any activities undertaken to implement a QIP, and any supporting information required to be maintained under these CAM requirements (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions) (40 CFR Part 64 § 64.9(b)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.11.2.2 Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements (40 CFR Part 64, §64.9(b)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

Tri-State maintains records as required. Monitor downtime is reported as required. Tri-State includes all excursions in Semi-Annual Monitoring and Deviations Reports, and Annual Compliance Certifications as required. A QIP has not been required by the Division.

Source is in compliance with this condition.

22.12 Savings Provisions

22.12.1 Nothing in these CAM requirements shall excuse the owner or operator of a source from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the federal clean air act. These CAM requirements shall not be used to justify the approval of monitoring less stringent than the monitoring which is required under separate legal authority and are not intended to establish minimum requirements for the purposes of determining the monitoring to be imposed under separate authority under the federal clean air act, including monitoring in permits issued pursuant to title I of the federal clean air act. The purpose of the CAM requirements is to require, as part of the issuance of this Title V operating permit, improved or new monitoring at those emissions units where monitoring requirements do not exist or are inadequate to meet the

requirements of CAM (40 CFR Part 64, §64.10(a)(1), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.2 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to impose additional or more stringent monitoring, recordkeeping, testing or reporting requirements on any owner or operator of a source under any provision of the federal clean air act, including but not limited to sections 114(a)(1) and 504(b), or state law, as applicable (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

22.12.3 Nothing in these CAM requirements shall restrict or abrogate the authority of the U.S. EPA or the Division to take any enforcement action under the federal clean air act for any violation of an applicable requirement or of any person to take action under section 304 of the federal clean air act (40 CFR Part 64, §64.10(a)(2), as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV).

Source is in compliance with this condition.

CONCLUSION

This compliance evaluation is based on observations made during the inspection, information provided by the source and a review of Division records. Tri-State Generation and Transmission, Inc. - Craig Station is determined to **not be in compliance** with the requirements of Operating Permit 95OPMF155 and Division regulations.

A. Pursuant to Operating Permit 96OPMF155, Permit Condition 10.4.1, Tri-State Generation and Transmission, Inc. - Craig Station is required to vent ash silos and dry ash unloaders (for commercial ash sale) to fabric filter baghouses. On August 16, 2024 from 10:30 AM to 11:30 AM, the S203a Ash Storage Silo A knife gate and flow control valve became stuck in the open position because of debris such as a wire brush, webbing, welding rods, pipe valves, and chunks of solidified ash resulting fly ash escaping from the S203a Ash Storage Silo truck loading chute and in fugitive particulate emissions from the S203a Ash Storage Silo Units 1 and 2 Fly Ash Silo Unloading area. Tri-State Generation and Transmission, Inc. - Craig Station failed to vent ash silos and dry ash unloaders (for commercial ash sale) to fabric filter baghouses in violation of Operating Permit 96OPMF155, Permit Condition 10.4.1.

This event was properly reported as malfunction, was determined to be a valid malfunction, and qualifies for the affirmative defense from enforcement (see Malfunction Section).

Source claims upset due to the S203a Ash Storage Silo A knife gate and flow control valve being stuck in the open position because of debris such as a wire brush, webbing, welding rods, pipe valves, and chunks of solidified ash resulting fly ash escaping from the S203a Ash Storage Silo truck loading chute and in fugitive particulate emissions from the S203a Ash Storage Silo Units 1 and 2 Fly Ash Silo Unloading area violating Permit Condition 10.4.1 requiring that ash silos and dry ash unloaders (for commercial ash sale) must be vented to fabric filter baghouses.

Eco Material Technologies (Eco) which purchases flay ash form Tri-State operates the fly ash truck loading at the facility.

As soon as Tri-State became aware of this issue, Tri-State scrubber personnel put on appropriate respiratory gear entered the flay ash unloading room and closed the emergency Shutoff valve. The valve is located upstream of the knife gate and the flow control valve. The knife gate and flow control valve were found to be stuck open with debris. Eco then cleaned out the silo after being cleared to reenter the area and normal operations resumed that day.

While the unloading room was minimally affected by dust the truck load out drive-through building area has a small pile of 1-2 tons of fly ash. High winds dusted the area to the east of the silo, including C road. The dust issues on the roads were immediately taken care of with the water truck once the fly ash leak was secured. The scrubber cleaning crew was diverted to the drive-through for clean up as well.

The source reported that the prompt investigation, emergency shut off, and cleaning activities served to minimize dust emissions and potential impacts associated with the event. No EPA Method 9 Visible Emissions Observations were conducted related to the event, and Tri-State reported that no off property transport of visible emissions was observed during the event.

Plat Operations works to vacuum out hoppers following a compartment outage but cannot always ensure that foreign material remains clear of the feeders. During silo outages an inspection is performed to clean and remove any foreign objects from the unloading chutes. Most findings are from years of accumulation and are considered unavoidable.

The week following this incident, ECO personnel went through training and retraining on where the emergency shut-off valve is located and the emergency response and hazard communication plan. Part of this training included updating their phone numbers for Tri-State and understanding who to call if this reoccurs.

Tri-State also moved the controls for emergency shut-off valve to a more easily accessible location outside of the fly ash unloading room and added a screen in the duct to prevent debris from reach the knife gate and flow control valve.

This event which occurred on a Friday was reported by telephone as a malfunction on the next following business day Monday, August 19, 2024. A follow-up report was received by the Division on January 28, 2025. This event is considered to be a valid malfunction.

Enforcement action is not recommended at this time.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-75:
Tri-State 2023 ERP Phase I Report

Colorado PUC E-Filings System



Tri-State Generation and Transmission Association, Inc.

2023 Electric Resource Plan

Phase I

(Colorado Public Utilities Commission Proceeding No. 23A-0585E)

April 22, 2024

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Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with 42 Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

Tri-State's Responsible Energy Plan (REP) issued in January of 2020 called for eliminating 100 percent of the carbon dioxide ("CO_2") emissions from Tri-State-owned coal generation in Colorado by 2030 and for 70 percent of the electricity used by its Members to come from clean sources by 2030. Tri-State has pursued an Electric Resource Plan (ERP) that aligns with its REP commitments.[1]

This is Tri-State's Phase I ERP. The plan complies with Colorado Public Utilities Commission (Commission) Rule 3605 and relevant paragraphs of Decision No. R22-0191 in Proceeding No. 20A-0528E issued March 28, 2022, approving the Unopposed Comprehensive Settlement Agreement (2020 ERP Settlement Agreement) filed with the Commission on January 18, 2022, concluding Phase I of Tri-State's 2020 ERP. Attachment A to this report identifies the components of this report and 2023 ERP Phase I filing that comply with Commission directives.

The 20-year[2] resource planning period (RPP) for the 2023 ERP is 2024-2043 and the resource acquisition period (RAP) is the six-year[3] period from 2026-2031. Although Tri-State evaluated "highly competitive"[4] bids for 2026 in Phase II of the 2020 ERP, given that no projects were ultimately procured, Tri-State included 2026 in the 2023 ERP RAP to assess whether additional near-term resources might be selected under updated modeling input assumptions. Tri-State selected an acquisition period of six years through 2031 to ensure that, as fossil resource retirements in Colorado occur through the end of the decade, sufficient resources would be in place to continue to meet resource adequacy and reliability requirements. The RAP also recognizes the extended lead-time for certain resource types.

Tri-State's preferred plan for its ERP is the IRA Scenario. The preferred plan is reliable, affordable, and responsible. The plan brings online 1,540 MW of new resources during the RAP, including:

- 700 MW of wind (200 MW of wind hybrids);
- 310 MW of storage (110 MW of standalone 100-hour iron air batteries; 100 MW of standalone 4-hour batteries; and 100 MW of 4-hr batteries with wind hybrids);
- 290 MW of combined-cycle natural gas in 2028 (with carbon capture and sequestration in 2031); and
- 240 MW of solar.

These resource additions are forecasted to result in one of the lowest present value revenue requirements (PVRR), among the scenarios modeled, over the planning period if Tri-State is awarded federal funding to

[1] The REP also identifies that Tri-State is striving for 100 percent clean energy in Colorado by 2040. While Phase I of the 2023 ERP does not yet forecast achievement of that stretch goal, Tri-State will continue to strive to make progress toward this aim in Phase II of the 2023 ERP and in the 2027 ERP. Notably, 2040 remains well outside of the Resource Acquisition Period (RAP) for the 2023 ERP.
[2] Commission Rule 3602(k).
[3] Commission Rules 3602(n) and 3605(a)(IV)(A).
[4] 2020 ERP Settlement Agreement, Section 3.4.4.2.

support generation additions and provide stranded asset relief under the U.S. Department of Agriculture's Empowering Rural America (New ERA) funding opportunity initiated by the Inflation Reduction Act of 2022 (IRA). The plan enables Tri-State to take full advantage of new direct pay of federal tax benefits for renewable and storage resources by increasing owned resources—while adding and maintaining PPA resources, which also helps to minimize renewable curtailment costs. The preferred plan also retires two coal-fired generation resources during the RAP, including:

- Craig Unit 3 (448 MW) on January 1, 2028; and
- Springerville Unit 3 (419 MW) on September 15, 2031.[5]

These significant shifts in Tri-State's generation portfolio over the coming years would result in an 89 percent greenhouse gas (GHG) emissions reduction related to Tri-State's wholesale sales of electricity in Colorado in 2030, over a 2005 baseline—more than any other scenario modeled in the 2023 ERP. The IRA Scenario results in the highest percentage of renewable generation capacity in 2030 (39 percent) while meeting all Level I and Level II reliability criteria, by maintaining sufficient dispatchable generation and bringing online new battery storage resources to ensure system performance during extreme weather events (EWEs).

Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data shows fourteen percent of the end-use customers served by Tri-State Members live below the federal poverty line, and up to half of the residential end-use customers suffer from some form of energy burden. The IRA has the potential to fundamentally alter the landscape for cooperative utilities. The IRA has "…tilt[ed] the balance in favor of cooperatives to develop their own renewables instead of utilizing purchase power agreements (PPAs). Thanks to the "direct-pay" provision in the law, cooperatives may now have a cost advantage depending on significant new grants from the U.S. Department of Agriculture (USDA) and the new ability to monetize tax credits that previously were available only to traditional developers with taxable income. These changes will have a big impact, as we saw when we compared renewables built by a representative cooperative versus an equivalent PPA…"[6]

Without new resource additions and assuming no change to previously announced generation retirement dates, with the exception of moving the Craig 3 retirement date to January 1, 2028, Tri-State would remain in a capacity-long position only through 2028, as identified in the 10-year loads and resources (L&R) shown in Table 1 below.[7] Under the IRA Scenario, Tri-State would remain capacity-long throughout the planning period[8], as shown in Figure 2 below.

[5] Predicated on Tri-State receiving New ERA funding as requested and negotiation of contractual agreements impacted by the resource plan.

[6] https://www.mcr-group.com/wp-content/uploads/2023/06/Coops-IRA-White-Paper_v3.pdf

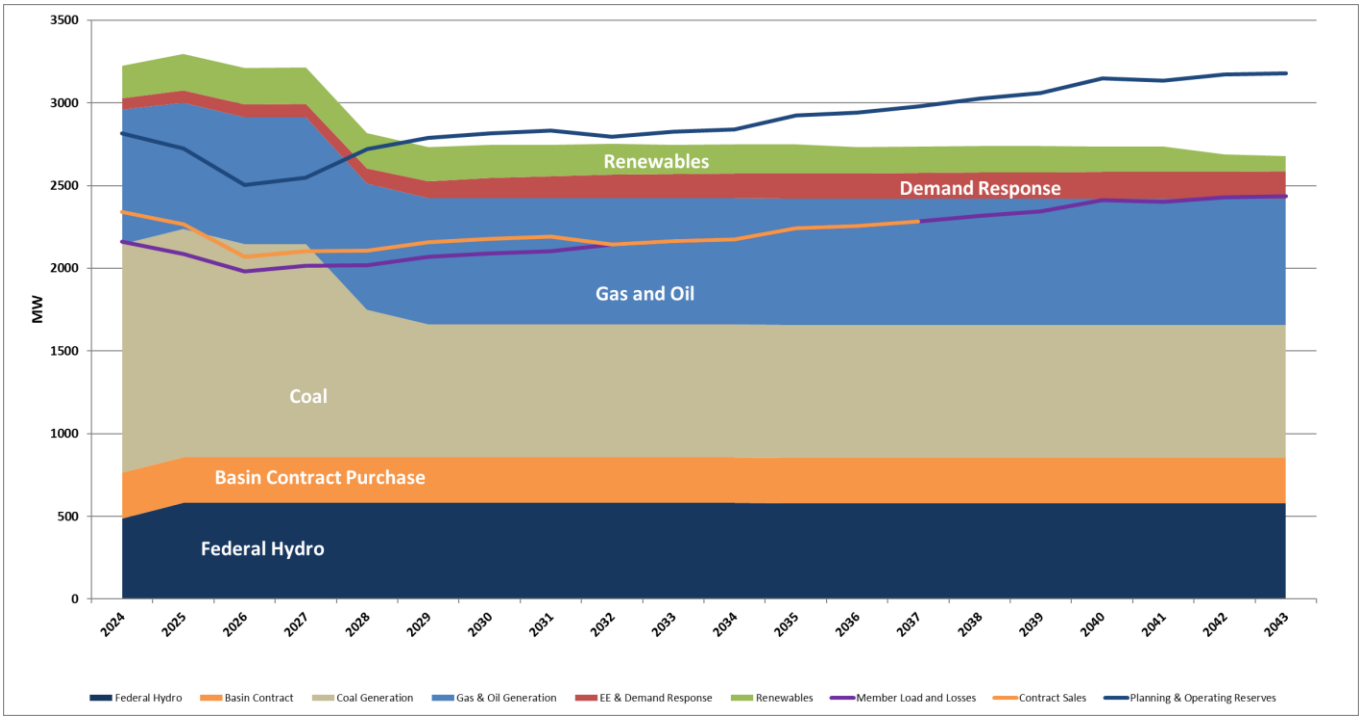
[7] In years where Tri-State files a Phase I ERP, the filing serves to comply with Commission Rule 3618(a) regarding ERP annual progress reports.

[8] The IRA scenario graph is reflective of all generic resources selected throughout the RPP but Tri-State will only be acquiring resources in the RAP (2026 to 2031).

Table 1: Load & Resources (L&R)[9]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Resources (MW)	3225	3298	3212	3215	2818	2734	2746	2747	2753	2747
Total Obligations (MW)[10]	2815	2725	2505	2549	2722	2790	2816	2835	2797	2827
Excess (MW)	409	572	708	667	95	-57	-71	-88	-43	-80

Figure 1: Load & Resources (L&R)[11]



[9] No new resource additions from 2023 ERP modeling are included, reflects the current Tri-State system with known, contracted resource additions from previous procurements.

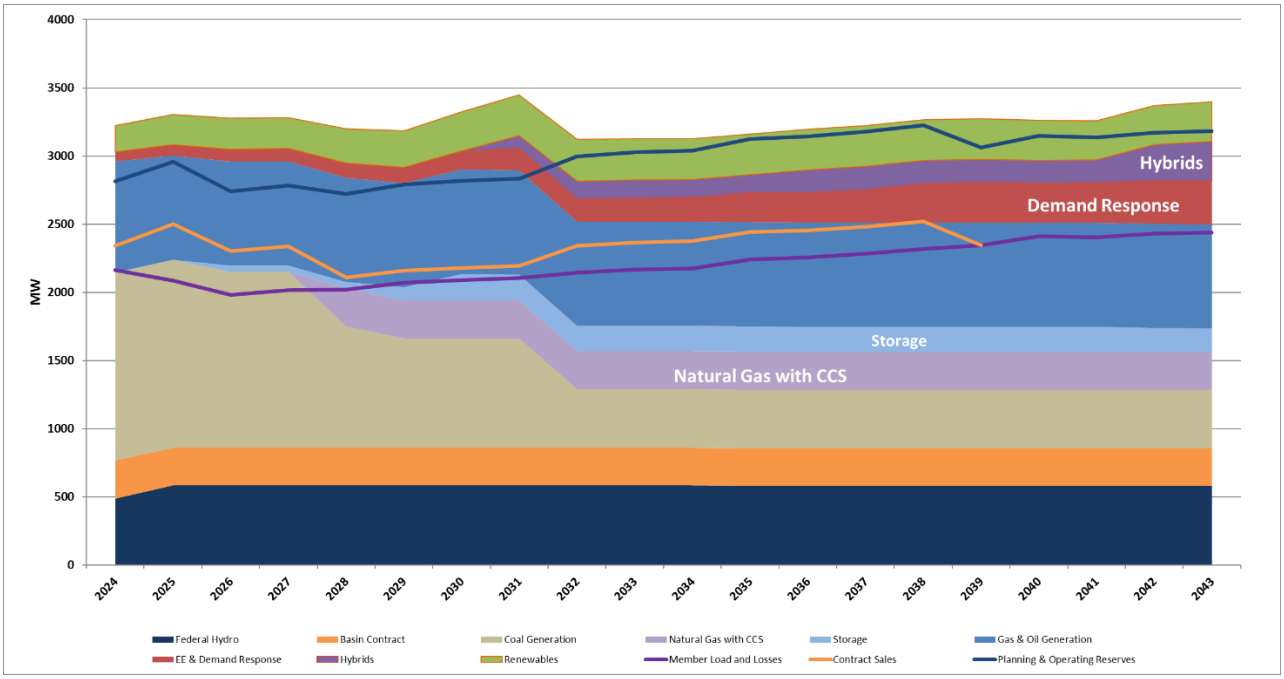
[10] Includes Member load (less energy efficiency and Partial Requirements, with Beneficial Electrification), losses, planning and operating reserves, and contract sales.

[11] No new resource additions from 2023 ERP modeling are included, reflects the current Tri-State system with known, contracted resource additions from previous procurements.

Table 2: Load & Resources (L&R), IRA Scenario

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Total Resources (MW)	3225	3303	3276	3281	3201	3184	3332	3448	3124	3124
Total Obligations (MW)[12]	2815	2959	2739	2783	2722	2790	2816	2835	2997	3027
Excess (MW)	409	344	537	499	478	393	506	613	127	97

Figure 2: Load & Resources (L&R), IRA Scenario



Modeling Inputs and Assumptions

Tri-State updated and modified all input assumptions for its 2023 ERP to reflect the best available information at the time modeling began in July 2023. Significant base modeling assumptions are identified and described in Attachment B and unique assumptions for each scenario are identified in Attachment B-3.

In addition to base modeling input assumptions reflective of the Tri-State system, best available information from reputable sources (such as national labs and technology vendors), and stakeholder

[12] Includes Member load (less energy efficiency and Partial Requirements, with Beneficial Electrification), losses, planning and operating reserves, and contract sales.

review and input, Tri-State also procured consultants to complete four studies that provide critical ERP inputs. The third-party completed studies are identified in Table 3 below.

Table 3: Third-Party Studies[13]

Third Party Study	Consultant	Description	Attachment
Effective Load Carrying Capability (ELCC) Study and PRM Analysis	Astrape	Determines reasonable capacity credits for wind, solar, and storage based on increasing resource penetration levels; and recommends updated planning reserve margin (PRM).	G-1
Benchmarking Study	Black & Veatch	Compares existing resources to generic resources in regard to cost and performance.	G-2
Beneficial Electrification Potential Study	Mesa Point Energy	Evaluates the achievable potential to convert non-electrical load to electrical load within Tri-State's Utility Member System territories while reducing carbon emissions.	G-3
Demand Side Management/Energy Efficiency Potential Study	Mesa Point Energy	Evaluates Demand Side Management achievable potential in relation to energy efficiency and demand response across Tri-State's Utility Member Systems' territories.	G-3
Evaluation of Tri-State G&T Preferred Plan (IRA Scenario) Reliability	Astrape	Evaluates reliability of preferred plan (IRA Scenario) in 2032	G-4

Tri-State also received input from ACES to analyze Tri-State's forward power curve forecasting and potential benefits of offering new products in an organized market, as well as related model set-up.

Assessment of Existing Resources

Tri-State's assessment of existing resources is provided in Attachment C-3. Resources capable of self-supplying certain ancillary services are identified in Attachment B-4. Information on Tri-State's PPA and contract resources is provided in Attachment C-1. An analysis of the performance of Tri-State's existing resources was performed by the third-party consultant, provided as a Benchmarking Study (Attachment G-2).

Electric Energy and Demand Forecast

Attachments F and F-1 contain Tri-State's load forecast summary and graphical presentation of load forecast data, pursuant to Commission Electric Rule 3605(a)(IV)(B) and 3605(b).

[13] Commission Rule 3605(a)(IV)(O).

Scenario Modeling and Analysis Summary

Tri-State modeled five scenarios for Phase I of the 2023 ERP: 1) the Business-as-Usual (BAU), 2) IRA, 3) Early Springerville 3 Retirement (ESPV3), 4) System Wide Emissions Reductions (SWER), and 5) Aggressive Colorado Emissions Reductions (ACER). Both the BAU and IRA Scenarios include modeling input assumptions that Tri-State believes to be the most accurate and reflective of its system operations and Members' needs. Scenarios 3, 4, and 5 were modeled at the request of stakeholders.

Additionally, two[14] sensitivity analyses were performed on each scenario's expansion plan to re-dispatch the plans under extreme weather event (EWE) and high gas (HG) price conditions. The EWE sensitivity modeling assumptions are provided in Attachment B-5 and results of the EWE sensitivity analyses are provided in this report. The assumptions and results for the HG sensitivity analysis are provided in Attachment E.

The Tri-State system is modeled as four planning regions. The planning regions are not state boundary restricted, rather they reflect significant power flow constraints within the Tri-State system:

- Wyoming / Electrically West Nebraska (WYO/WNE*)* – includes Tri-State owned or contracted resources capable of interconnecting north of TOT 3 in Wyoming and Nebraska located in the western interconnection and Western Area Colorado Missouri (WACM) Balancing Authority (BA);[15] and Tri-State load identified as WACM BA Wyoming loads.
- Eastern Colorado (ECO) – includes Tri-State owned or contracted resources capable of connecting to transmission in Colorado south of TOT 3, east of TOT 5, and in the western interconnection and WACM BA; and Tri-State load identified as WACM BA east loads and Tri-State loads in Public Service Company of Colorado (PSCO) BA.
- Western Colorado (WCO) – includes Tri-State owned or contracted resources capable of connecting to transmission in Colorado north of TOT 2, west of TOT 5, and east of TOT 1 in WACM BA; and Tri-State load identified as WACM BA west load.
- New Mexico (NM) – includes Tri-State load and owned or contracted resources physically located in or pseudo-tied into Public Service of New Mexico (PNM) BA. PNM BA is located in New Mexico and a portion of southeast Colorado.

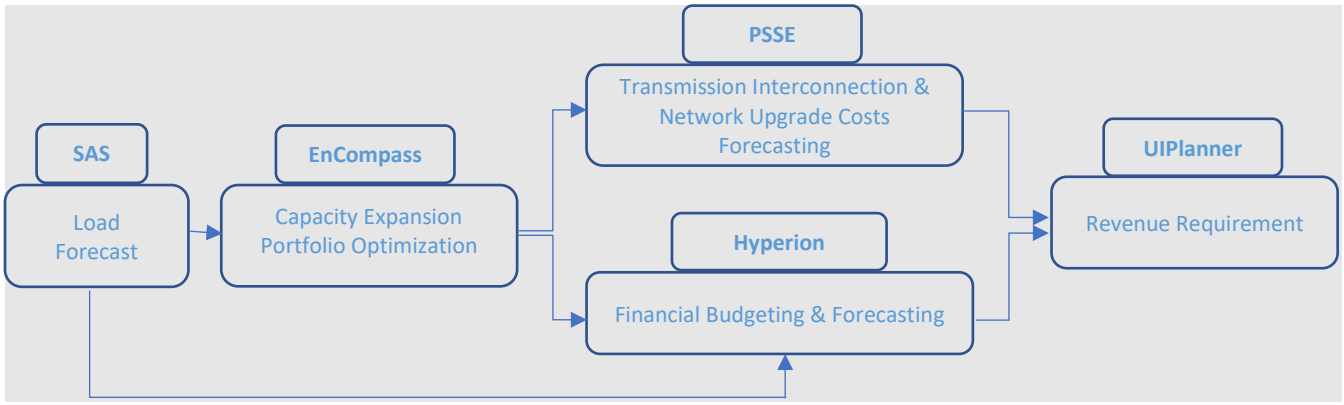
Additional detail on the Tri-State system reflected in the EnCompass model is available in Attachment B-6: Tri-State System Topology.

Figure 3 below identifies the software tools (SAS, EnCompass, PSSE, Hyperion, and UIPlanner) utilized by Tri-State for completing each component of the scenario analyses and the succession of data through each system.

[14] Tri-State contemplated performing a drought sensitivity analysis for one year of the BAU Scenario, however, at the time 2023 ERP modeling began the U.S. Bureau of Reclamation's latest five-year projection for the Colorado River system indicated 0 percent probability of minimum power pool through 2027, so Tri-State deferred drought analysis to a future ERP.

[15] TOTs represent a collection of transmission lines identified as a transfer path between regions.

Figure 3: Modeling Software Tools



Each scenario was evaluated in terms of its performance under reliability, financial, and environmental criteria, and state renewable policy compliance, as described below.

Expansion Plan, Retirements, System Mix, and Capacity Factors

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase I modeling, inputting the applicable modeling assumptions described in Attachment B[16] and reflecting the Tri-State system topology, provided as Attachment B-6.

Environmental Analyses

Based on the expansion plan and dispatch produced for each scenario, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon (SCoC) and social cost of methane (SCoM). SCoC values reflect the February 2021 Interagency Working Group (IWG) on Social Cost of Greenhouse Gases, Technical Support Document.[17]

For each scenario, Tri-State separately produced an Air Pollution Control Division (APCD) verification workbook (APCD Workbook) calculating forecasted carbon emissions reductions, provided in Attachment D.[18] Target-year emissions reductions percentages for each scenario, calculated from the APCD Workbooks, are provided in this report.

Tri-State used the most recent available EPA eGRID rates, year 2021, for forecasted market purchases and sales, the Basin Eastern Interconnection contract, and the Basin Electrically Western Interconnection contract. The carbon emission rate assumption for market purchases and sales is 1,159 pounds per MWh through 2029 per 2021 RMPA eGRID rate and 450 pounds per MWh (WECC), per APCD Workbook requirement, starting in 2030. The carbon emission rate assumption for Basin Western Interconnection contract is 2,596 pounds per MWh 2024 through 2025 per 2021 LRS eGRID rate, 1,159 pounds per MWh 2026 through 2029 per 2021 RMPA eGRID rate, and 450 pounds per MWh (WECC), per APCD Workbook

[16] *See* Attachments B, B-1, B-2, and B-3.
[17] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf
[18] 2020 ERP Settlement Agreement, Section 3.11.1.

requirement, starting in 2030. The carbon emission rate assumption for Basin Eastern Interconnection contract is 996 pounds per MWh through 2029, which is the 2021 MROW[19] eGRID rate and 525 pounds per MWh (SPP), per APCD Workbook requirement starting in 2030.

Financial Analyses

Tri-State and 39 of our 42 Members serve 170 census tracts that are identified as Disadvantaged Communities, and 161 census tracts are identified as Low Income.[20] Pursuant to Rule 3605(g)(III)(C)(iii), Tri-State provided a financial analysis of each scenario, including:

- Annual revenue requirements;
- Present value revenue requirement, with and without the social costs of carbon and methane; and
- Curtailment MWhs by intermittent resource type seasonally and year.[21]

Transmission Analyses

Each scenario was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades.

Reliability Analyses

Tri-State utilizes industry standard reliability metrics for its resource planning, referred to in the ERP as "Level I Reliability Metrics," and has also developed an additional set of reliability metrics for assessing the plan's performance under simulated EWE conditions, and refers to those standards as "Level II Reliability Metrics." All metrics are given equal weight as minimum requirement thresholds for any scenario to be supported as a reliable, preferred plan for Tri-State.

These metrics are critical for mitigating risks associated with:

- Not meeting resource adequacy obligations as a load-serving entity (LSE);
- Reliability impacts during a single EWE as well as the impact of EWEs on reliability over the course of the RAP;
- Uncertainty of performance of emerging technologies and contribution of increased intermittent resources at higher levels;
- Lost productivity and cost of deploying emergency response measures during an EWE; and
- Member reliability expectations for high reliability across the system and limited load shedding or reduced system reliability during an EWE, and over time.

[19] Midwest Reliability Organization West

[20] Council on Environmental Quality Climate and Economic Justice Screening Tool (Explore the map - Climate & Economic Justice Screening Tool (geoplatform.gov), and USDA look-up map (Locations of Distressed and Disadvantaged Communities (arcgis.com).

[21] One of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order. In the event that resources must be curtailed, Tri-State's model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic min and must take contracts (i.e., hydropower and Basin contracts)–in that order.

Level 1 reliability metric checks were performed on each scenario, including:

- *Planning Reserve Margin (PRM):* Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%). The third-party study of PRM (Attachment G-1) was developed using a Strategic Energy Risk Valuation Model (SERVM)—a system-reliability planning and production cost model designed to analyze the capabilities of an electric system during a variety of conditions under thousands of different scenarios and is thus able to identify potential risks to system reliability across the entire year, not just at system peak. The model, therefore, provides insight into risks and costs during these periods as well as the expectation of being able to meet peak load under many, varying conditions. The results of the model help determine the amount of reserves an electric system requires to adequately maintain system reliability.
    - Target (min) is 22% transitioning to 30.5% in 2028 after the retirement of the Craig facility.
- *Loss of Load Hours (LoLH)*[22]: Measure of the likelihood of failing to meet system load (hours per 10 years).
    - Target (max) is 1 day in 10 years (99.973% reliability).[23]
        - 2024-2033 – annually cannot exceed 2.4 hours.[24]
        - 2034-2043 – cannot exceed 24 hours over entire period.
- *Expected Unserved Energy (EUE)*[25]: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
    - Targets (max):
        - ≤ 0.4 GWh annually.[26]

Level 2 reliability target checks were performed on each scenario's EWE sensitivity result, including:

- ≤ 12 loss of load hours during all EWEs in 2026-2031
- ≤ 3 loss of load hours per each year, 2026-2031
- EUE must be ≤ 20% of load in any hour[27]

[22] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2020 ERP Phase I.

[23] Splitting the LOLH target over the planning period reflects Tri-State's desire to have added assurance that intra-year reliability in the near-term is met by resources coming online during the RAP as the generation fleet makes significant transitions through this period. This approach also allows Tri-State to cautiously assess the impact of having an increasing percentage of intermittent resources in its fleet and the uncertain potential for more severe EWEs before applying similarly stringent LOLH metrics to the outer years of the planning period. There is more flexibility allowed in the out years as forecasting and technology uncertainty is greater during this period.

[24] The annual LOLH target of 2.4 hours is an equivalent representation of the 1 day in 10 years reliability standard.

[25] EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.

[26] This metric is reflective of lower load forecasted based on both member exits and Partial Requirements and is aimed at limiting EUE to a reasonable level below the historical annual average, consistent with the 2020 ERP Phase II.

[27] This metric is an equivalent to the Level I annual EUE target, reflected as an hourly target to assess reliability during EWE stress periods. According to NREL, ~26 percent of estimated load in ERCOT was curtailed during Winter Storm Uri in 2021.

- Evaluation of market purchases vs remaining hourly available dispatchable capacity to ensure that EUE was not avoided through the use of market purchases as capacity.[28]

A detailed analysis of how additions of new intermittent capacity can serve load and maintain reliability is provided for each scenario.[29]

State Renewable Policy Compliance Analysis

Tri-State reviewed the results of each scenario and affirms that all scenarios meet or exceed the minimum applicable state renewable energy standard (RES) or renewable portfolio standard (RPS) requirements. RES/RPS standards are shown in the following table.

Table 4: Colorado RES and New Mexico RPS Requirements during RPP

	Colorado RES[30, 31]		New Mexico RPS[32]
	Co-ops	Tri-State	Co-ops
2024	10%	20%	10%
2025-2029	10%	20%	40%
2030-2050	10%	20%	50%

Comparative Analysis

The analysis Tri-State completed to compare and assess results across scenarios can be found in the Comparative Analysis section of this report.

Commission Electric Rule 3605(g)(III)(C) and (D)

The Commission must consider the following factors in issuing a Phase I decision:

The Phase I decision will set forth the information the utility shall provide in the ERP Implementation Report regarding potential resources, proposed utility-owned resources, and the modeling of portfolio combinations of resources to support the development of cost-effective resource plans.

Tri-State proposes an outline for the ERP Implementation Report to be filed in Phase II of the 2023 ERP, provided as Attachment LKT-3.

Tri-State proposes to procure utility-owned resources and PPAs, in alignment with the resource mix modeled in the IRA Scenario, shown in the table below. This approach would result in approximately 500 MW of owned resources and 1040 MW of PPA resources.

[28] In evaluating historical events, Tri-State confirmed that there was no reliance on third party capacity during extreme weather events. If market purchases occurred an equal or greater amount of Tri-State capacity was unused.
[29] 2020 ERP Settlement Agreement, Section 3.11.14.
[30] § 40-2-124(1)(c)(I)(D) and (c)(V)(D), C.R.S.
[31] § 40-2-124(8)(b), C.R.S.
[32] N.M. Stat. Ann. § 62-15-34.

Table 5: Proposed MW of Utility-Owned and PPA Resources, by Technology, in IRA Scenario RAP

Technologies	Own	PPA
Solar		240
Wind		500
Wind Hybrid		200
4-hr Storage[33]	100	100
Iron Air Storage	110	
Natural Gas Combined Cycle (NGCC) with Carbon Capture and Sequestration (CCS) Conversion	290	
Total	**500**	**1040**

The Commission shall determine the cost of carbon dioxide emissions to assess the cost, benefit, and net present value of revenue requirements to be presented in the ERP Implementation Report.

Tri-State has utilized the most recent IWG on Social Cost of Greenhouse Gases, Technical Support Document for the SCoC at the time modeling began and suggests continuation of that practice is sufficient for reporting portfolio analysis results in Phase II of the 2023 ERP.

In consideration of the base case portfolio of resources and alternative portfolios proposed by the utility, the Commission shall define the base case portfolio and alternative portfolios for modeling in Phase II.

If New ERA funding is received as requested, Tri-State requests that the IRA Scenario be the base case portfolio in Phase II. Tri-State proposes to model one portfolio that reflects the IRA Scenario resource selections and five portfolios that identifies back-up bid selections for each technology cohort. Tri-State requests limiting stakeholder-requested portfolios to two, given the number of back-up bid portfolios that will be necessary.

The Commission may require the utility to provide information regarding alternative portfolios in addition to the base case portfolio and information regarding the cost, benefit, and net present value of revenue requirements of the alternative portfolios using different levels of costs for carbon dioxide.

Tri-State has provided cost, benefit, and PVRRs for five scenarios in Phase I, including a base case (Business as Usual Scenario), and would provide similar information for Phase II portfolios.

In accordance with § 40-3.2-106(3), C.R.S., the Commission shall establish the relevant factors other than the cost of carbon dioxide emissions for consideration of the approval of the utility's electric resource plan.

Factors that Tri-State has considered in evaluation of its preferred plan, the IRA Scenario, are identified in the Executive Summary and Comparative Analysis sections of this report. Factors include reliability, financial, and environmental considerations.

[33] Owned storage is standalone and PPA storage is tied to 200 MW of wind (wind hybrid).

The Phase I decision will establish the deadline for the utility to submit its ERP Implementation Report.

Tri-State has proposed a Phase II timeline (Attachment LKT-2), which plans for the ERP Implementation Report to be filed 120 days after Bid Evaluation Complete (estimated to be January 2025). The proposed timeline for the ERP Implementation Report aims to ensure sufficient time for modeling preparation and completion, while recognizing RAP includes 2026.

Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in ongoing stakeholder engagement in advance of and during the Phase I resource planning process. Numerous stakeholder groups representing a diverse set of interests participated in more than a dozen meetings in 2023 in advance of Tri-State beginning Phase I modeling and several additional meetings during development of the Phase I filing. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform participants of key modeling inputs and assumptions, and facilitate dialogue on topics applicable to Phase I. These stakeholder meetings occurred between January and October 2023, covering the following topics:

1. January 17, 2023: Phase I Scope, Timeline, Generic Resources, Storage Valuation, ELCCs, Scenarios/Sensitivities, and Phase II RFP[34]
2. February 16, 2023: Beneficial Electrification (BE) Meeting #1[35]
3. February 23, 2023: Phase I Storage Valuation, ELCCs, DSM/DR/BE,[36] and Scenarios/Sensitivities[37]
4. March 10, 2023: Phase I Scenario and Sensitivity Planning #1[38]
5. March 14, 2023: Phase I Reliability and Extreme Weather Event (EWE) Sensitivities
6. March 22, 2023: BE Meeting #2[39]
7. March 24, 2023: Phase I Reliability and Extreme Weather Sensitivities
8. March 27, 2023: Phase I Scenario and Sensitivity Planning #2[40]
9. April 24, 2023: Phase I Battery Modeling and ELCC Study[41]
10. April 26, 2023: DSM Roundtable Meeting #1
11. May 4, 2023: Phase I Scenario and Sensitivity Planning #3 (GHG Reduction Modeling)[42]
12. May 17, 2023: Phase I Pre-Modeling Assumptions Feedback[43]

[34] 2020 ERP Settlement Agreement, Sections 3.11.12., 3.11.13 and 3.11.15.
[35] 2020 ERP Settlement Agreement, Section 3.11.10.
[36] Per 2020 ERP Settlement Agreement, Sections 3.11.5, Tri-State held three meetings on DSM prior to December 31, 2022 which were identified in the 2020 ERP Phase II Implementation Report (April 27, June 14, and August 1, 2022). DSM modeling was also discussed during the February 23, 2023 stakeholder meeting.
[37] 2020 ERP Settlement Agreement, Sections 3.11.12, 3.11.13, and 3.11.14.
[38] 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.
[39] 2020 ERP Settlement Agreement, Section 3.11.10.
[40] 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.
[41] 2020 ERP Settlement Agreement, Section 3.11.13.
[42] 2020 ERP Settlement Agreement, Section 3.11.12.
[43] 2020 ERP Settlement Agreement, Section 3.11.12.

13. July 19, 2023: Phase I PRM, ELCC, and EWE Modeling[44]
14. August 14, 2023: Phase I Scenario and Sensitivity Planning #4[45]
15. September 27, 2023: Phase II Planning[46]
16. October 18, 2023: DSM Roundtable Meeting #2

Several other meetings, e-mail communications and updates to stakeholders also occurred in advance of and during Phase I modeling with the aim of ensuring communications on key ERP topics.[47] All 2023 ERP stakeholder meetings were identified on Tri-State's website[48] in advance of the meetings and were open for public participation.[49]

Tri-State maintains ongoing collaboration with interested stakeholders related to its ERP, federal funding pursuits, and organized market-related matters.

Scenario Results: Highlights

Key facets of the scenario modeling results, such as generic resource selection during the RAP, and unit retirements modeled and PVRRs over the RPP are summarized below. Detailed scenario results and comparisons across scenarios are in the sections that follow.

Generic Resource Selection in Scenario Modeling

Table 6 identifies the generic resource types selected across the scenarios modeled.

Table 6: Generic Resources Selected in Scenario Modeling During the RAP, by MW and Technology

Scenario	Gas	Storage[50]	Solar[51]	Wind	Wind Hybrid	Total
Scenario 1: BAU	290	250	140	0	300	**980**
Scenario 2: IRA	290	310	240	500	200	**1,540**
Scenario 3: ESPV3	290	350	140	0	300	**1,080**
Scenario 4: SWER	290	50	140	0	100	**580**
Scenario 5: ACER	290	100	140	0	200	**730**

Unit Retirement Selection in Scenario Modeling

Table 7 identifies the retirements dates modeled for resources during the RPP.

[44] 2020 ERP Settlement Agreement, Section 3.11.13.
[45] 2020 ERP Settlement Agreement, Section 3.11.12 and 3.11.14.
[46] Decision No. C23-0437, at¶ 67.
[47] Of note, discussion of emissions rates occurred August 16, 2022, per 2020 ERP Settlement Agreement, Section 3.11.4, as identified in the 2020 ERP Phase II Implementation Report.
[48] https://tristate.coop/resource-planning
[49] 10 C.F.R. § 905.11(b)(4)
[50] Storage inclusive of standalone and hybrid batteries.
[51] Solar values are representative of selected generic resources during the RAP. Due to the cancellation of the Coyote Gulch after the start of modeling, 140 MW of solar replacement in 2026 will be pursued in Phase II and is reflected in this data.

Table 7: Retirements Modeled by Scenario

Scenario	Craig 3	SPV 3	LRS 2
Scenario 1: BAU	1/1/2028	1/1/2037	1/1/2043
Scenario 2: IRA	1/1/2028	9/15/2031	N/A
Scenario 3: ESPV3	1/1/2028	1/1/2031	N/A
Scenario 4: SWER	1/1/2028	1/1/2037	N/A
Scenario 5: ACER	1/1/2028	1/1/2037	1/1/2042

Scenario PVRRs

Error! Reference source not found. identifies the PVRRs resulting from each scenario modeled, over the RPP.

Table 8: PVRR by Scenario

Scenario	PVRR ($, Millions)
Scenario 1: BAU	$17,507.40
Scenario 2: IRA	$17,221.40
Scenario 3: ESPV3	$17,304.20
Scenario 4: SWER	$17,343.90
Scenario 5: ACER	$17,208.20

Phase I Scenario Results and Analysis

Each section that follows presents data and analytical results from each scenario modeled, addressed in the following order:

- Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales/Purchases
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

1. Business As Usual (BAU) Scenario

The BAU Scenario and assumptions served as the base case scenario for Phase I.[52] Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 1 (BAU) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, DSM selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

[52] Commission Rule 3605(a)(IV)(M).

Table 9: Expansion Plan (Scenario 1 – BAU)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[53]	West Colorado	140	1	140
2028	NGCC with CCS[54]	West Colorado	290	1	290
2030	Wind/Battery Hybrid	East Colorado	100	2	200
	100 hr – Iron Air Battery	East Colorado	100	1	100
2031	Wind/Battery Hybrid	New Mexico	100	1	100
2032	Wind/Battery Hybrid	East Colorado	100	1	100
2033	Wind	East Colorado	100	1	100
2036	Wind/Battery Hybrid	East Colorado	100	1	100
2037	Wind/Battery Hybrid	New Mexico	100	1	100
2040	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100
2041	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100
2042	Wind/Battery Hybrid	East Colorado	100	2	200
	Wind/Battery Hybrid	Wyoming / W. Neb.	100	2	200
2043	Solar	New Mexico	100	1	100
	Wind/Battery Hybrid	Wyoming / W. Neb.	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[55]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[56]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 1 – BAU in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 1 – BAU in 2040.

The expansion plan also included the following Demand Response (DR) levels by region:[57]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[58]
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 1 – BAU starting in 2040.
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 1 – BAU starting in 2038.

[53] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[54] NGCC installed in 2028 and CCS conversion startup anticipated in 2031.
[55] Commission Rule 3605(c)(I)(I).
[56] 2020 ERP Settlement Agreement at Section 3.11.6.
[57] Commission Rule 3605(c)(I)(I).
[58] 2020 ERP Settlement Agreement at Section 3.11.8.

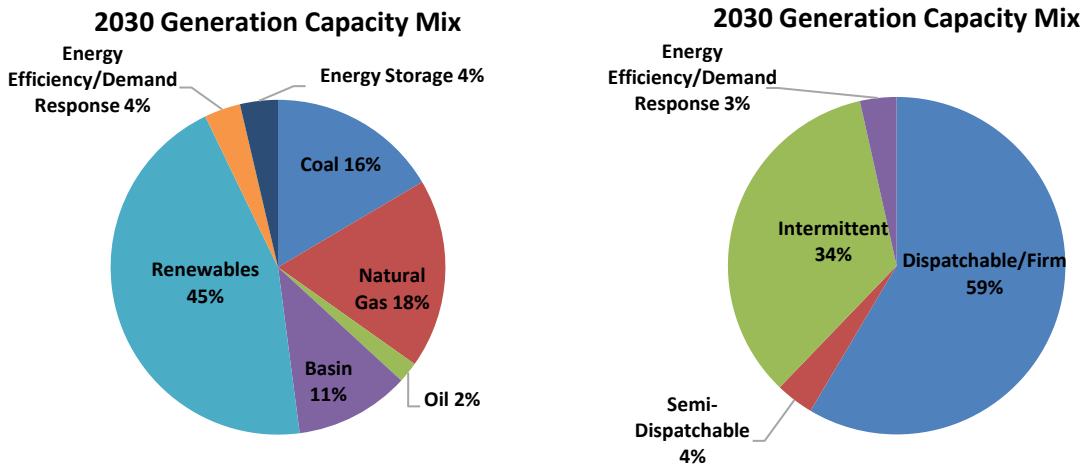
Unit retirements selected in the modeling are shown in the following table.[59]

Table 10: Modeled Retirements (Scenario 1 – BAU)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037
LRS 2 (TS portion)	241	Coal	1/1/2043[60]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 4: Projected Tri-State System Resource Mix 2030 (Scenario 1 – BAU)[61, 62, 63]



[59] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[60] This a modeling result based on input assumptions for Tri-State's portion of Laramie River Station (LRS) Unit 2; at the time of this report, Tri-State does not have the right to unilaterally retire any Missouri Basin Power Project (MBPP) resource (LRS 2 or LRS 3). Tri-State along with MBPP participants will continue to evaluate changing industry regulations, system and market conditions to inform operational decisions related to its joint owned coal units.
[61] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[62] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[63] System Energy Mix reflects sales to Members and non-Members.

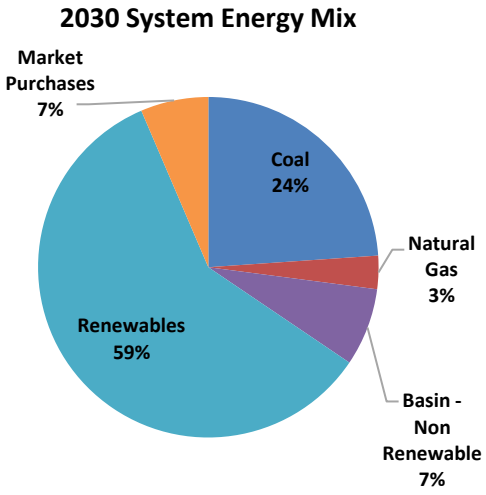


Table 11: Projected Annual Capacity Factors for Thermal Resources (Scenario 1 – BAU)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	18%	0%	0%	0%	0%	0%	0%
Craig 2	98%	15%	27%	12%	15%	0%	0%	0%
Craig 3	79%	13%	22%	18%	0%	0%	0%	0%
LRS 2	93%	89%	86%	78%	76%	74%	71%	70%
LRS 3	75%	63%	62%	55%	57%	48%	45%	51%
SPV 3	72%	67%	43%	42%	43%	36%	44%	42%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	26%	11%	0%	1%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	28%	28%	19%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 12: Forecasted Energy Sales and Purchases (Scenario 1 – BAU)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,534	1,506	3,095	2,877	3,344	2,774	3,286	3,911
Purchases (GWh)	344	946	523	884	610	717	926	742

Scenario 1 (BAU) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 13: Environmental Impact - System Wide (Scenario 1 – BAU)[64]

Year	CO_2 [65] (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,834,465	7,750	10,740	0.0383	704	6,777,851,478	32,082
2025	10,918,985	5,416	6,423	0.0243	515	4,098,496,075	20,000
2026[66]	8,555,344	5,071	5,977	0.0230	413	3,640,953,702	18,040
2027	8,004,261	4,747	5,558	0.0204	378	3,239,042,574	16,444
2028	7,398,021	4,273	4,742	0.0182	384	3,109,973,662	14,569
2029	6,751,561	3,964	4,414	0.0161	336	2,752,993,696	12,908
2030	5,884,898	4,044	4,477	0.0161	350	2,732,958,152	13,397
2031	5,745,992	4,070	4,513	0.0166	370	3,287,323,551	13,629
2032	5,310,741	3,880	4,343	0.0153	333	3,053,750,612	12,597
2033	5,652,647	4,035	4,490	0.0162	361	3,227,998,157	13,431
2034	5,698,340	4,065	4,532	0.0163	362	3,244,468,138	13,533
2035	5,458,062	3,970	4,464	0.0157	339	3,116,848,744	12,923
2036	5,083,006	3,833	4,367	0.0149	302	2,923,162,545	12,018
2037	4,083,249	3,443	4,075	0.0130	206	2,443,989,009	9,470
2038	4,101,311	3,456	4,095	0.0130	206	2,447,420,964	9,511
2039	4,167,871	3,501	4,158	0.0132	208	2,466,937,312	9,661
2040	4,173,730	3,512	4,178	0.0131	207	2,460,238,397	9,674
2041	4,163,504	3,509	4,183	0.0130	205	2,442,136,997	9,651
2042	4,205,424	3,542	4,241	0.0130	205	2,439,323,762	9,744
2043	2,858,155	2,789	3,381	0.0071	127	1,651,568,018	6,808
Total	**124,049,570**	**82,870**	**97,350**	**0.337**	**6,512**	**61,557,435,546**	**270,090**
Pounds/Gallons per MWh[67]	857	0.57	0.67	0.000002	0.04	213	2.056

[64] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[65] In all scenarios the 2021 eGRID emission rate for LRS is used for calculating emissions of the Basin Western Interconnection Contract in 2024 and 2025. This is a change from reporting in the 2020 ERP which used regional eGRID rates in those years. From 2026 to 2029 the 2021 RMPA eGRID is used for this contract which then transitions to the APCD assigned rate for WECC in 2030.

[66] Load reduced due to partial requirements contracts in 2026 forward.

[67] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 14: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 1 – BAU)

Year	Annual Social Cost of Carbon
2024	$1,390,597,459
2025	$995,687,914
2026	$810,659,426
2027	$787,912,259
2028	$755,247,562
2029	$714,655,955
2030	$645,736,709
2031	$653,860,869
2032	$626,587,101
2033	$691,336,216
2034	$722,286,260
2035	$716,850,786
2036	$691,597,305
2037	$575,435,014
2038	$598,539,612
2039	$629,766,814
2040	$652,840,646
2041	$670,965,445
2042	$705,605,295
2043	$494,486,160

Table 15: Social Cost of Methane Nominal Dollars – System Wide (Scenario 1 – BAU)

Year	Annual Social Cost of Methane
2024	$82,734,317
2025	$54,056,308
2026	$51,119,484
2027	$48,825,849
2028	$45,233,558
2029	$41,884,087
2030	$45,409,865
2031	$48,392,878
2032	$46,826,362
2033	$52,235,896
2034	$55,037,923
2035	$54,924,746
2036	$53,357,940
2037	$43,900,675
2038	$46,012,180
2039	$48,752,421
2040	$50,897,483
2041	$52,750,303
2042	$56,102,875
2043	$40,040,866

Table 16: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 1 – BAU)

Year	Target[68]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	68%
2030	80%	86%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 1 (BAU) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[68] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Table 17: Total Financial (Scenario 1 – BAU)

$, Millions	**Scenario PVRR** (2023 WACC 4.12%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Scenario PVRR inclusive of SCoC NPV**	**Scenario PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,507.4	$11,608.8	$800.2	$29,116.2	$29,916.4
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,806.8				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$598.2				

Table 18: Annual Financial (Nominal $) (Scenario 1 – BAU)

Year	**Total Annual Revenue Requirement ($, Millions)**
2024	$1,016
2025	$987
2026	$898
2027	$966
2028	$1,053
2029	$1,218
2030	$1,262
2031	$1,283
2032	$1,305
2033	$1,399
2034	$1,503
2035	$1,519
2036	$1,562
2037	$1,461
2038	$1,490
2039	$1,514
2040	$1,534
2041	$1,544
2042	$1,566
2043	$1,734

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 19: Total Financial Under **EWE** Sensitivity (Scenario 1 – BAU)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,472.1

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 1 – BAU dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the investment tax credit (ITC) they do not have a production tax credit (PTC) penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 1 – BAU are $518,551.

Table 20: Curtailed Intermittent Energy, Annual MWh (Scenario 1 – BAU)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,653	0	0	**5,653**
2027	0	3,345	0	0	**3,345**
2028	0	2,732	0	0	**2,732**
2029	0	2,193	0	0	**2,193**
2030	0	0	0	0	**0**
2031	0	0	0	0	**0**
RAP Total	**0**	**13,923**	**0**	**0**	**13,923**

Table 21: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 1 – BAU)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	125	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**150**	**11,870**	**86**	**1,817**

The following table reflects PPA pricing, penalties, and taxes.

Table 22: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 1 – BAU)

	Wind ($)	Solar ($)
2024	0	0
2025	0	0
2026	0	$208,078
2027	0	$125,060
2028	0	$102,674
2029	0	$82,738
2030	0	0
2031	0	0
RAP Total	**$0**	**$518,550**

Scenario 1 (BAU) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the point of interconnection (POI), resulting from the scenario are shown in the table below.

Table 23: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 1 – BAU)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		$2.88	
2030	100	Wind + Battery		$2.88	
2030	100	Battery	$1.40	$2.88	
2032	100	Wind + Battery		$2.88	
2033	100	Wind		$2.88	
2036	100	Wind + Battery		$10.20	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	$1.50	$4.20	
Wyoming (WYO) Transmission Area					
2040	100	Wind + Battery		$12.00	$109.00
2041	100	Wind		$4.20	
2042	100	Wind + Battery		$4.20	
2042	100	Wind + Battery		$4.20	$34.00
2043	100	Wind + Battery		$4.20	
New Mexico (NM) Transmission Area)					
2031	100	Wind + Battery		$2.88	$238.50
2037	100	Wind + Battery		$2.88	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Solar		$1.68	

Scenario 1 (BAU) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 24: Planning Reserve Margin, % Annual (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	49%	42%	52%	54%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 25: Loss of Load Probability, Hours (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 26: Expected Unserved Energy, Annual MWh (Scenario 1 – BAU)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 1 – BAU)

Section 3.11.14. of the 2020 ERP Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 1 – BAU, 150 MW of 4-hour hybrid storage, 100 MW of long-duration storage, and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP, and support integration of intermittent resources.

Scenario 1 (BAU) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 27 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all twelve EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the Scenario 1 – BAU extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours in Scenario 1 – BAU.

Table 27: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 1 – BAU)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 28 represents any EUE identified by hour in the twelve EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 28: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 1 – BAU)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed EWE performance for Scenario 1 – BAU in the post-RAP period and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 1 – BAU)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 1 – BAU, market was used for 6.4 GWh in 118 hours during the January EWE events between 2026-2031. The market was used for 11.9 GWh in 80 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

2. Inflation Reduction Act of 2022 (IRA) Scenario

Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 2 (IRA) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 29: Expansion Plan (Scenario 2 – IRA)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	4hr – Battery	New Mexico	50	1	50
	100hr – Iron Air Battery	East Colorado	10	1	10
	Solar[69]	West Colorado	140	1	140
2028	Wind	Wyoming / W. Neb.	100	2	200
	NGCC with CCS[70]	West Colorado	290	1	290
2029	Solar	New Mexico	100	1	100
	4hr – Battery	East Colorado	50	1	50
	Wind	East Colorado	100	1	100
2030	Wind	East Colorado	100	1	100
	Wind	Wyoming / W. Neb.	100	1	100
	100hr – Iron Air Battery	East Colorado	100	1	100
2031	Wind/Battery	New Mexico	100	2	200
2032	Wind/Battery	New Mexico	100	1	100
2036	Wind/Battery	East Colorado	100	1	100
2042	Wind/Battery	East Colorado	100	3	300
	Wind	Wyoming / W. Neb.	100	1	100
2043	Wind/Battery	Wyoming / W. Neb.	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[71]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[72]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 2 – IRA in 2025.

[69] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[70] NGCC installed in 2028 and CCS conversion startup anticipated 2031.
[71] Commission Rule 3605(c)(I)(I).
[72] 2020 ERP Settlement Agreement at Section 3.11.6.

- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 2 – IRA in 2025.

The expansion plan also included the following Demand Response (DR) levels by region:[73]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[74]
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 2 – IRA starting in 2035.
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 2 – IRA starting in 2038.

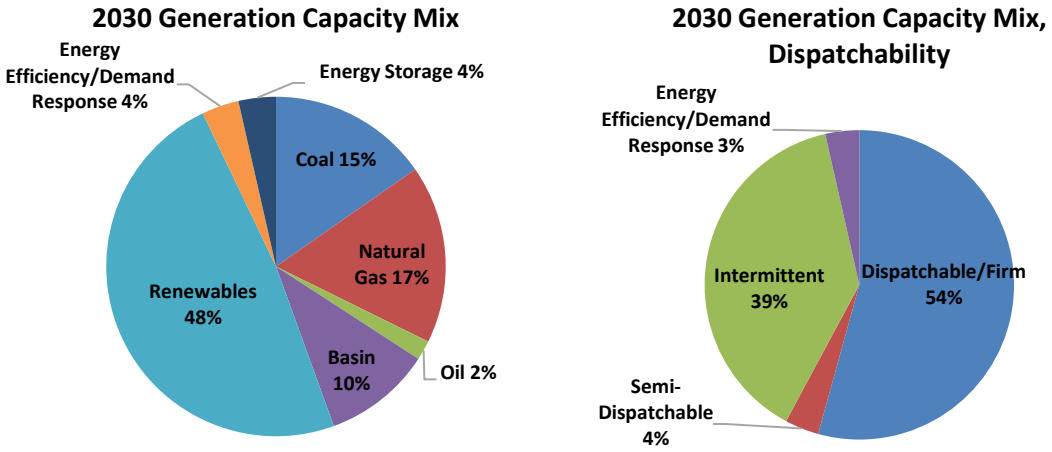
Unit retirements modeled are shown in the following table.[75]

Table 30: Modeled Retirements (Scenario 2 – IRA)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	9/15/2031

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 5: Projected Tri-State System Resource Mix 2030 (Scenario 2 – IRA)[76, 77, 78]



[73] Commission Rule 3605(c)(I)(I).
[74] 2020 ERP Settlement Agreement at Section 3.11.8.
[75] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[76] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[77] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[78] System Energy Mix reflects sales to Members and non-Members.

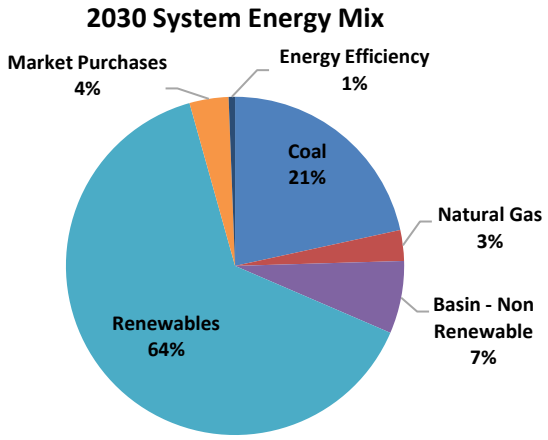


Table 31: Projected Annual Capacity Factors for Thermal Resources (Scenario 2 – IRA)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	18%	0%	0%	0%	0%	0%	0%
Craig 2	97%	16%	35%	25%	34%	0%	0%	0%
Craig 3	78%	12%	22%	17%	0%	0%	0%	0%
LRS 2	93%	89%	71%	71%	71%	68%	63%	64%
LRS 3	75%	64%	72%	60%	57%	55%	49%	50%
SPV 3	64%	66%	42%	42%	42%	36%	42%	37%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	0%	0%	0%	0%	0%	0%	0%
Shafer	26%	11%	1%	1%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	27%	25%	19%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 32: Forecasted Energy Sales and Purchases (Scenario 2 – IRA)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,304	1,499	3,067	2,873	3,957	3,883	4,259	5,014
Purchases (GWh)	283	952	515	813	422	422	542	512

Scenario 2 (IRA) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 33: Environmental Impact - System Wide (Scenario 2 – IRA)[79]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,451,106	7,595	10,593	0.0376	674	6,622,378,196	31,305
2025	10,888,923	5,401	6,381	0.0243	515	4,078,147,420	19,913
2026[80]	8,468,490	4,994	5,893	0.0225	408	3,590,666,662	17,862
2027	7,993,868	4,710	5,504	0.0204	380	3,249,891,892	16,483
2028	7,253,155	4,178	4,625	0.0178	381	3,076,352,800	14,438
2029	6,563,974	3,928	4,348	0.0163	333	2,735,998,999	12,813
2030	5,608,261	3,884	4,262	0.0155	337	2,634,907,653	12,808
2031	4,831,239	3,643	4,079	0.0145	299	2,871,821,954	11,464
2032	3,824,819	3,280	3,865	0.0122	194	2,334,603,678	8,895
2033	3,933,841	3,345	3,952	0.0125	199	2,379,546,703	9,139
2034	3,964,238	3,367	3,982	0.0126	200	2,385,882,853	9,211
2035	3,927,079	3,349	3,971	0.0123	197	2,356,788,752	9,117
2036	3,985,696	3,392	4,021	0.0125	199	2,381,021,036	9,258
2037	4,022,648	3,417	4,064	0.0125	200	2,384,355,478	9,343
2038	4,021,708	3,421	4,072	0.0125	199	2,375,788,747	9,338
2039	3,974,658	3,373	3,968	0.0128	203	2,414,033,911	9,235
2040	3,998,873	3,400	4,018	0.0127	201	2,401,751,376	9,291
2041	3,983,443	3,399	4,036	0.0124	198	2,364,432,696	9,251
2042	4,027,793	3,434	4,095	0.0124	198	2,363,931,030	9,354
2043	4,013,781	3,433	4,106	0.0122	195	2,338,232,936	9,322
Total	**114,737,592**	**78,943**	**93,836**	**0.318**	**5,707**	**57,340,534,771**	**247,837**
Pounds/Gallons per MWh[81]	792	0.55	0.65	0.000002	0.04	198	1.886

[79] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[80] Load reduced due to partial requirements contracts in 2026 forward.

[81] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 34: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 2– IRA)

Year	Annual Social Cost of Carbon
2024	$1,356,930,446
2025	$992,946,534
2026	$802,429,547
2027	$786,889,198
2028	$740,458,538
2029	$694,799,728
2030	$615,381,995
2031	$549,767,216
2032	$451,270,783
2033	$481,120,934
2034	$502,482,209
2035	$515,774,643
2036	$542,296,523
2037	$566,894,764
2038	$586,922,384
2039	$600,572,264
2040	$625,490,158
2041	$641,947,763
2042	$675,801,518
2043	$694,419,551

Table 35: Social Cost of Methane Nominal Dollars – System Wide (Scenario 2 – IRA)

Year	Annual Social Cost of Methane
2024	$80,730,077
2025	$53,818,969
2026	$50,613,362
2027	$48,939,435
2028	$44,826,979
2029	$41,577,985
2030	$43,413,041
2031	$40,707,122
2032	$33,064,168
2033	$35,541,561
2034	$37,457,706
2035	$38,749,984
2036	$41,103,874
2037	$43,309,094
2038	$45,174,789
2039	$46,600,954
2040	$48,883,426
2041	$50,563,745
2042	$53,858,083
2043	$54,827,634

Table 36: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 2 – IRA)

Year	Target[82]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	67%
2030	80%	89%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 2 (IRA) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[82] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Table 37: Total Financial (Scenario 2 – IRA)

$, Millions	**Scenario PVRR** (2023 WACC 4.12%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Scenario PVRR inclusive of SCoC NPV**	**Scenario PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,221.4	$10,726.7	$733.1	$27,948.1	$28,681.2
Expansion Plan CapEx + IDC: Generation (Nominal $)	$2,093.9				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$555.5				

Table 38: Annual Financial (Nominal $) (Scenario 2 – IRA)

Year	**Total Annual Revenue Requirement ($, Millions)**
2024	$1,017
2025	$969
2026	$904
2027	$962
2028	$1,104
2029	$1,231
2030	$1,258
2031	$1,301
2032	$1,285
2033	$1,317
2034	$1,349
2035	$1,379
2036	$1,416
2037	$1,440
2038	$1,464
2039	$1,506
2040	$1,566
2041	$1,593
2042	$1,601
2043	$1,700

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 39: Total Financial Under **EWE** Sensitivity (Scenario 2 – IRA)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,166.8

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 2 – IRA dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 2 – IRA are $503,718.

Table 40: Curtailed Intermittent Energy, Annual MWh (Scenario 2– IRA)

	Existing Wind	**Existing Solar**	**Generic Wind**	**Generic Solar**	**Total**
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	75	0	0	**75**
2027	0	0	0	0	**0**
2028	0	287	0	0	**287**
2029	0	583	0	1,197	**1,780**
2030	0	376	0	203	**579**
2031	0	632	154	3,633	**4,419**
RAP Total	**0**	**1,953**	**154**	**5,033**	**7,140**

Table 41: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 2 – IRA)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	0	75	0	0
2027	0	0	0	0
2028	7	280	0	0
2029	1	1,572	0	207
2030	0	579	0	0
2031	0	3,902	13	504
RAP Total	**8**	**6,408**	**13**	**711**

The following table reflects PPA pricing, penalties, and taxes.

Table 42: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 2 – IRA)

	Wind ($)	Solar ($)
2024	0	0
2025	0	0
2026	0	$2,816
2027	0	$0
2028	0	$9,596
2029	0	$122,947
2030	0	$29,692
2031	$8,765	$329,902
RAP Total	**$8,765**	**$494,953**

Scenario 2 (IRA) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 43: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 2 – IRA)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2026	10	Battery	$1.40	$2.88	
2029	50	Battery	$1.40	$2.88	
2029	100	Wind		$2.88	
2030	100	Wind		$2.88	
2030	100	Battery	$1.40	$2.88	
2036	100	Wind + Battery		$2.88	
2042	100	Wind		$10.20	
2042	100	Wind		$2.88	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2042	100	Wind		$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	$1.50	$4.20	
Wyoming (WYO) Transmission Area					
2028	100	Wind		$12.00	$109.00
2028	100	Wind		$4.20	
2030	100	Wind		$4.20	
2042	100	Wind		$4.20	$26.00
2043	100	Wind + Battery		$4.50	
New Mexico (NM) Transmission Area)					
2026	50	Battery		$2.88	
2029	100	Solar		$1.68	
2031	100	Wind + Battery		$2.88	$238.50
2031	100	Wind + Battery		$2.88	
2032	100	Wind + Battery		$2.88	

Scenario 2 (IRA) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 44: Planning Reserve Margin, % Annual (Scenario2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	49%	47%	54%	50%	55%	60%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 45: Loss of Load Probability, Hours (Scenario 2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
0	1	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 46: Expected Unserved Energy, Annual MWh (Scenario 2 – IRA)

2024	2025	2026	2027	2028	2029	2030	2031
0	1	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 2 – IRA)

Section 3.11.14. of the 2020 ERP Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 2 – IRA, 200 MW of short duration storage, 110 MW of long duration storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 2 (IRA) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 47: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 2– IRA)Table 47 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all twelve EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 47: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 2– IRA)

Event (Season/Year)	Date	Hour
All Event Periods	N/A	N/A

Table 48 represents any EUE identified by hour in the twelve EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 48: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 2 – IRA)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All Event Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 2 –IRA)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 2 – IRA, the market was used for 5.5 GWh in 97 hours during the January EWE events between 2026-2031. The market was used for 11.5 GWh in 79 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics.

Market purchases during these limited hours were confirmed to not lean on the market for capacity.

3. Early Springerville 3 Retirement Scenario (ESPV3)

Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 3 (ESPV3) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 49: Expansion Plan (Scenario 3 – ESPV3)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[83]	West Colorado	140	1	140
2028	4hr – Battery	West Colorado	50	1	50
	NGCC with CCS[84]	West Colorado	290	1	290
2030	Wind/Battery	East Colorado	100	1	100
2031	4hr – Battery	West Colorado	50	1	50
	Wind/Battery	New Mexico	100	2	200
	100hr – Iron Air Battery	East Colorado	100	1	100
2036	Wind	East Colorado	100	1	100
2037	Wind	East Colorado	100	2	200
2039	Wind/Battery	Wyoming / W. Neb.	100	1	100
2040	Wind/Battery	Wyoming / W. Neb.	100	1	100
2041	Wind	Wyoming / W. Neb.	100	2	200
2042	Wind/Battery	East Colorado	100	3	300
2043	Solar	New Mexico	100	1	100
	Wind/Battery	Wyoming / W. Neb	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[85]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[86]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 3 – ESPV3 in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 3 – ESPV3 in 2040.

[83] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[84] NGCC installed in 2028 and CCS conversion startup anticipated in 2031.
[85] Commission Rule 3605(c)(I)(I).
[86] 2020 ERP Settlement Agreement at Section 3.11.6.

The expansion plan also included the following Demand Response (DR) levels by region:[87]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[88]
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 3 – ESPV3 starting in 2031.
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 3 – ESPV3 starting in 2031

Unit retirements selected in the modeling are shown in the following table.[89]

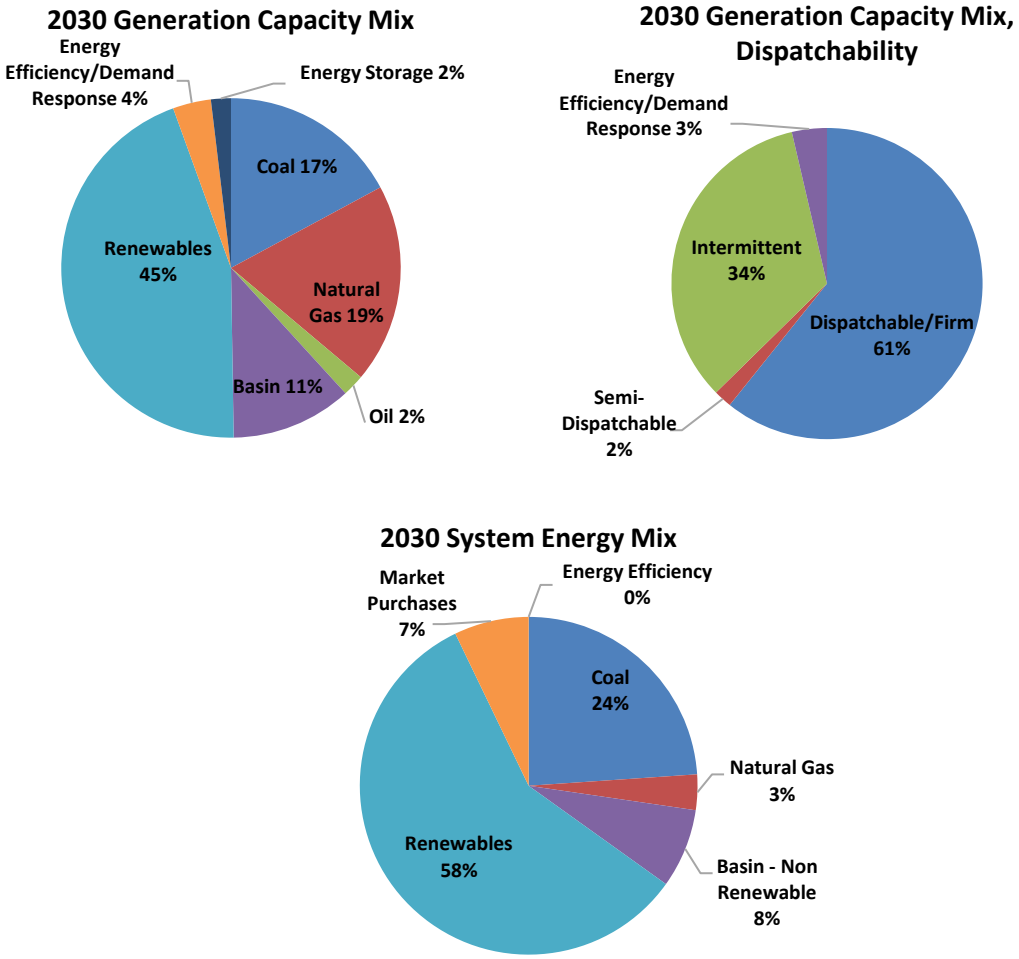
Table 50: Modeled Retirements (Scenario 3 –ESPV3)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2031

Resulting system capacity and energy mix, based on the modeling are shown below.

[87] Commission Rule 3605(c)(I)(I).
[88] 2020 ERP Settlement Agreement at Section 3.11.8.
[89] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").

Figure 6: Projected Tri-State System Resource Mix 2030 (Scenario 3 – ESPV3)[90, 91, 92]



[90] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[91] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[92] System Energy Mix reflects sales to Members and non-Members.

Table 51: Projected Annual Capacity Factors for Thermal Resources (Scenario 3 – ESPV3)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	16%	0%	0%	0%	0%	0%	0%
Craig 2	98%	9%	34%	23%	20%	0%	0%	0%
Craig 3	79%	14%	22%	16%	0%	0%	0%	0%
LRS 2	93%	89%	71%	71%	71%	69%	63%	64%
LRS 3	75%	64%	70%	60%	58%	51%	48%	54%
SPV 3	72%	67%	43%	42%	43%	37%	44%	0%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	24%	11%	1%	0%	0%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	29%	28%	20%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 52: Forecasted Energy Sales and Purchases (Scenario 3 – ESPV3)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,505	1,506	3,044	2,850	3,312	2,712	3,018	3,098
Purchases (GWh)	355	946	545	852	623	722	1,004	1,167

Scenario 3 (ESPV3) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 53: Environmental Impact - System Wide (Scenario 3 – ESPV3)[93]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,839,102	7,764	10,741	0.0383	704	6,772,194,117	32,129
2025	10,919,154	5,447	6,450	0.0245	513	4,099,792,207	19,995
2026[94]	8,469,494	4,985	5,874	0.0224	409	3,579,117,374	17,834
2027	7,999,822	4,707	5,493	0.0203	381	3,238,736,958	16,456
2028	7,332,465	4,209	4,671	0.0177	380	3,069,522,031	14,392
2029	6,711,585	3,942	4,388	0.0160	333	2,727,887,902	12,834
2030	5,808,252	3,998	4,428	0.0157	345	2,680,280,773	13,221

[93] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[94] Load reduced due to partial requirements contracts in 2026 forward.

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2031	3,936,370	3,337	3,931	0.0126	201	2,399,903,106	9,134
2032	3,835,588	3,290	3,891	0.0121	193	2,324,000,130	8,911
2033	3,950,512	3,360	3,986	0.0124	198	2,369,472,111	9,166
2034	3,982,627	3,382	4,019	0.0125	199	2,377,578,327	9,240
2035	3,951,406	3,370	4,016	0.0122	196	2,345,304,444	9,165
2036	4,026,737	3,423	4,077	0.0125	199	2,380,608,886	9,347
2037	4,060,785	3,435	4,078	0.0128	203	2,416,104,215	9,428
2038	4,051,989	3,435	4,086	0.0126	201	2,399,586,707	9,406
2039	4,098,100	3,460	4,108	0.0129	204	2,432,494,784	9,515
2040	4,094,950	3,467	4,124	0.0128	203	2,419,226,942	9,510
2041	4,088,441	3,459	4,110	0.0128	203	2,420,432,239	9,492
2042	4,131,169	3,499	4,190	0.0127	201	2,399,136,160	9,588
2043	4,099,795	3,483	4,170	0.0125	199	2,380,264,589	9,520
Total	**115,388,344**	**79,453**	**94,833**	**0.318**	**5,667**	**57,231,644,003**	**248,282**
Pounds/Gallons per MWh[95]	797	0.55	0.65	0.000002	0.04	198	1.890

Table 54: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 3 – ESVP3)

Year	Annual Social Cost of Carbon
2024	$1,391,004,648
2025	$995,703,293
2026	$802,524,764
2027	$787,475,263
2028	$748,555,145
2029	$710,424,496
2030	$637,326,494
2031	$447,936,321
2032	$452,541,393
2033	$483,159,901
2034	$504,813,123
2035	$518,969,660
2036	$547,880,617
2037	$572,269,158
2038	$591,341,514
2039	$619,224,271
2040	$640,518,145
2041	$658,868,730
2042	$693,146,438
2043	$709,300,764

[95] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 55: Social Cost of Methane Nominal Dollars – System Wide (Scenario 3 – ESPV3)

Year	Annual Social Cost of Methane
2024	$82,855,374
2025	$54,041,930
2026	$50,535,594
2027	$48,861,264
2028	$44,684,056
2029	$41,645,072
2030	$44,814,668
2031	$32,432,806
2032	$33,124,403
2033	$35,647,372
2034	$37,577,397
2035	$38,954,135
2036	$41,497,117
2037	$43,705,831
2038	$45,503,307
2039	$48,013,151
2040	$50,034,448
2041	$51,880,457
2042	$55,205,912
2043	$55,991,156

Table 56: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 3 – ESPV3)

Year	Target[96]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	67%
2030	80%	85%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 3 (ESPV3) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[96] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Table 57: Total Financial (Scenario 3 – ESPV3)

$, Millions	**Scenario PVRR** (2023 WACC 4.12%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Scenario PVRR inclusive of SCoC NPV**	**Scenario PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,304.2	$10,789.6	$734.8	$28,093.8	$28,828.6
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,983.6				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$590.6				

Table 58: Annual Financial (Nominal $) (Scenario 3 – ESPV3)

Year	**Total Annual Revenue Requirement ($, Millions)**
2024	$1,016
2025	$988
2026	$904
2027	$962
2028	$1,060
2029	$1,178
2030	$1,441
2031	$1,335
2032	$1,345
2033	$1,361
2034	$1,382
2035	$1,404
2036	$1,428
2037	$1,450
2038	$1,474
2039	$1,495
2040	$1,514
2041	$1,529
2042	$1,546
2043	$1,562

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 59: Total Financial Under **EWE** Sensitivity (Scenario 3 – ESPV3)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,275.6

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 3 – ESPV3 dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 3 – ESPV3 are $520,955.

Table 60: Curtailed Intermittent Energy, Annual MWh (Scenario 3 – ESPV3)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,640	0	0	**5,640**
2027	0	3,345	0	0	**3,345**
2028	0	2,732	0	0	**2,732**
2029	0	2,193	0	0	**2,193**
2030	0	0	0	0	**0**
2031	0	0	44	0	**44**
RAP Total	**0**	**13,910**	**44**	**0**	**13,954**

Table 61: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 3 – ESPV3)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	112	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	44	0	0
RAP Total	**137**	**11,914**	**86**	**1,817**

The following table reflects PPA pricing, penalties, and taxes.

Table 62: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 3 – ESPV3)

	Wind ($)	Solar ($)
2024	$0	$0
2025	$0	$0
2026	$0	$208,309
2027	$0	$124,914
2028	$0	$102,651
2029	$0	$82,570
2030	$0	$0
2031	$2,511	$0
RAP Total	**$2,511**	**$518,444**

Scenario 3 (ESPV3) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 63: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 3 – ESPV3)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		$2.88	
2031	100	Battery	$1.40	$2.88	
2036	100	Wind		$10.20	
2037	100	Wind		$2.88	
2037	100	Wind		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2028	290	Gas	$1.50	$4.20	
2028	50	Battery	$1.40	$2.88	
2031	50	Battery	$1.40	$2.88	
Wyoming (WYO) Transmission Area					
2039	100	Wind + Battery		$12.00	$109.00
2040	100	Wind + Battery		$4.20	
2041	100	Wind		$4.20	
2041	100	Wind		$4.20	$26.00
2043	100	Wind + Battery		$4.20	
New Mexico (NM) Transmission Area)					

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2031	100	Wind + Battery		$2.88	$238.50
2031	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 3 (ESPV3) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 64: Planning Reserve Margin, % Annual (Scenario 3 –ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	52%	44%	47%	48%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 65: Loss of Load Probability, Hours (Scenario 3 – ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 66: Expected Unserved Energy, Annual MWh (Scenario 3 – ESPV3)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 3 – ESPV3)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 3 – ESPV3, 250 MW of 4-hr storage, 100 MW of long-duration storage, and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable

resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 3 (ESPV3) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 67 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 67: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 3 – ESPV3)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 68 represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 68: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 3 – ESPV3)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 3 – ESPV3)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
  - NM Market HE 2 to HE 6 and HE 11 to 15
  - 1 day in event no market depth
- Summer:
  - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
  - 1 day in event no market depth

In the EWE analysis for Scenario 3—ESPV3, the market was used for 7.4 GWh in 131 hours during the January EWE events between 2026-2031. The market was used for 14.3 GWh in 85 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

4. System-wide Emissions Reduction Scenario (SWER)

Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 4 (SWER) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 69: Expansion Plan (Scenario 4 – SWER)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[97]	West Colorado	140	1	140
2029	NGCC with CCS[98]	West Colorado	290	1	290
2030	Wind/Battery	East Colorado	100	1	100
2033	Wind	New Mexico	100	1	100
	Wind/Battery	New Mexico	100	1	100
2034	Wind/Battery	East Colorado	100	1	100
2036	Wind/Battery	East Colorado	100	1	100
2037	Wind/Battery	New Mexico	100	1	100
2038	Wind/Battery	East Colorado	100	1	100
2040	Wind/Battery	Wyoming / W. Neb.	100	1	100
2041	Wind	Wyoming / W. Neb.	100	2	200
2042	Wind	East Colorado	100	1	100
	Wind/Battery	East Colorado	100	2	200
2043	Solar – Build Transfer	West Colorado	100	3	300
	Solar	New Mexico	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[99]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[100]

The expansion plan also included the following Demand Response (DR) levels by region:[101]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[102]

[97] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[98] NGCC installed in 2029 and CCS conversion startup anticipated in 2031.
[99] Commission Rule 3605(c)(I)(I).
[100] 2020 ERP Settlement Agreement at Section 3.11.6.
[101] Commission Rule 3605(c)(I)(I).
[102] 2020 ERP Settlement Agreement at Section 3.11.8.

- 39 MW of Wyoming low level Demand Response was selected in the expansion plan of Scenario 4 – SWER starting in 2030.
- 117 MW New Mexico moderate level Demand Response was selected in the expansion plan of Scenario 4 – SWER starting in 2039.

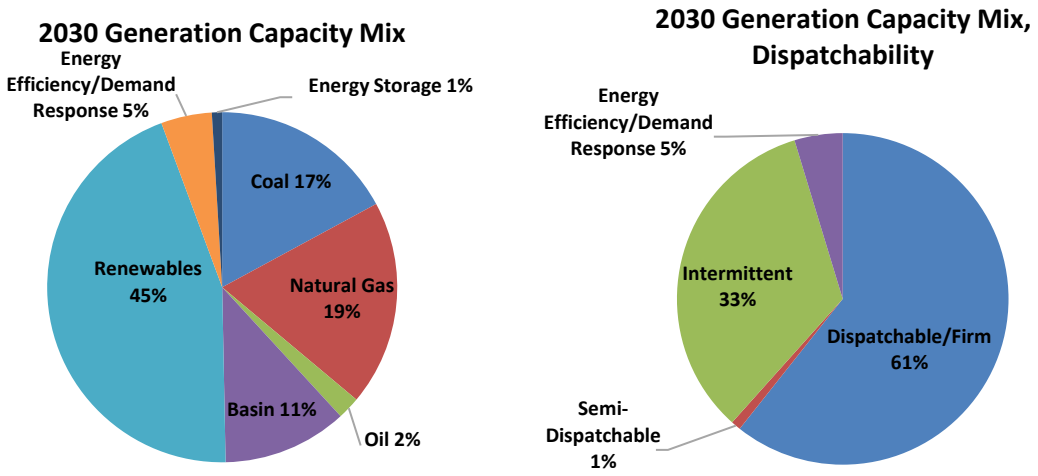
Unit retirements selected in the modeling are shown in the following table.[103]

Table 70: Modeled Retirements (Scenario 4 – SWER)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 7: Projected Tri-State System Resource Mix 2030 (Scenario 4- SWER)[104, 105, 106]



[103] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[104] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[105] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[106] System Energy Mix reflects sales to Members and non-Members.

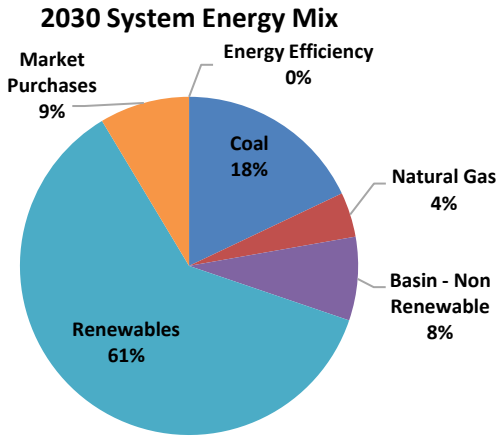


Table 71: Projected Annual Capacity Factors for Thermal Resources (Scenario 4 - SWER)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	17%	0%	0%	0%	0%	0%	0%
Craig 2	98%	16%	26%	13%	36%	0%	0%	0%
Craig 3	79%	13%	25%	19%	0%	0%	0%	0%
LRS 2	93%	89%	71%	72%	71%	67%	41%	16%
LRS 3	75%	64%	69%	57%	58%	50%	30%	13%
SPV 3	72%	67%	43%	42%	45%	36%	37%	36%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	27%	11%	0%	1%	1%	0%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	0%	29%	24%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 72: Forecasted Energy Sales and Purchases (Scenario 4 – SWER)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,561	1,496	3,063	2,872	2,902	2,615	2,245	1,687
Purchases (GWh)	346	941	550	912	748	658	1,154	1,265

Scenario 4 (SWER) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 73: Environmental Impact - System Wide (Scenario 4 - SWER)[107]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,863,704	7,761	10,763	0.0383	705	6,793,247,708	32,133
2025	10,919,812	5,420	6,407	0.0244	516	4,098,699,996	19,995
2026[108]	8,477,517	5,026	5,962	0.0225	404	3,583,422,154	17,903
2027	7,972,529	4,721	5,542	0.0202	374	3,210,051,302	16,365
2028	7,358,120	4,302	4,787	0.0182	377	2,927,811,446	14,845
2029	6,573,723	3,872	4,303	0.0156	327	2,680,149,760	12,556
2030	4,514,050	3,295	3,646	0.0108	262	1,990,503,327	10,296
2031	3,157,659	2,666	2,918	0.0062	212	1,818,549,023	7,869
2032	3,203,866	2,736	3,048	0.0067	205	1,845,960,399	7,905
2033	3,208,225	2,703	2,972	0.0063	213	1,829,638,245	7,985
2034	3,226,798	2,710	2,973	0.0064	215	1,851,008,307	8,024
2035	3,254,631	2,763	3,078	0.0069	208	1,876,225,341	8,012
2036	3,315,308	2,850	3,219	0.0077	200	1,929,252,664	8,076
2037	3,614,749	3,177	3,763	0.0110	179	2,178,755,684	8,428
2038	3,622,455	3,180	3,760	0.0111	181	2,189,879,374	8,448
2039	3,611,385	3,180	3,770	0.0110	178	2,169,009,462	8,423
2040	3,596,535	3,182	3,782	0.0108	176	2,145,151,059	8,397
2041	3,613,093	3,188	3,781	0.0109	178	2,160,677,499	8,433
2042	3,585,634	3,191	3,825	0.0104	171	2,091,352,778	8,369
2043	3,610,874	3,196	3,807	0.0107	175	2,135,484,251	8,432
Total	**106,300,669**	**73,119**	**86,106**	**0.266**	**5,456**	**51,504,829,781**	**230,898**
Pounds/Gallons per MWh[109]	734	0.50	0.59	0.000002	0.04	178	1.757

[107] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[108] Load reduced due to partial requirements contracts in 2026 forward.

[109] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 74: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 4 – SWER)

Year	Annual Social Cost of Carbon
2024	$1,393,165,248
2025	$995,763,266
2026	$803,284,931
2027	$784,788,638
2028	$751,174,190
2029	$695,831,712
2030	$495,316,652
2031	$359,323,495
2032	$378,007,746
2033	$392,375,842
2034	$409,008,952
2035	$427,456,666
2036	$451,083,112
2037	$509,411,285
2038	$528,656,041
2039	$545,681,555
2040	$562,557,798
2041	$582,264,404
2042	$601,614,118
2043	$624,713,086

Table 75: Social Cost of Methane Nominal Dollars – System Wide (Scenario 4 - SWER)

Year	Annual Social Cost of Methane
2024	$82,867,370
2025	$54,042,415
2026	$50,729,638
2027	$48,591,361
2028	$46,092,106
2029	$40,743,674
2030	$34,900,045
2031	$27,942,182
2032	$29,384,966
2033	$31,054,907
2034	$32,634,103
2035	$34,054,127
2036	$35,858,109
2037	$39,068,247
2038	$40,865,813
2039	$42,504,595
2040	$44,182,882
2041	$46,091,559
2042	$48,190,439
2043	$49,596,337

Table 76: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 4 - SWER)

Year	Target[110]	Forecast
2025	26%	47%
2026	36%	60%
2027	46%	68%
2030	80%	82%

Table 77: System-wide GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 4 - SWER)

Year	Target[111]	Forecast
2027	20.9%	44%
2028	33.2%	44%
2029	45.4%	51%
2030	57.7%	61%
2031	70%	73%

See Appendix D for detailed GHG emissions calculations for the scenario.

[110] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.
[111] 2020 ERP Settlement Agreement, Sections 3.3.4. and 3.3.5.

Scenario 4 (SWER) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

Table 78: Total Financial (Scenario 4 - SWER)

$, Millions	**Scenario PVRR** (2023 WACC 4.12%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Scenario PVRR inclusive of SCoC NPV**	**Scenario PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,343.9	$9,899.2	$679.1	$27,243.1	$27,922.2
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,694.1				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$546.3				

Table 79: Annual Financial (Nominal $) (Scenario 4 - SWER)

Year	**Total Annual Revenue Requirement ($, Millions)**
2024	$1,016
2025	$978
2026	$894
2027	$957
2028	$1,003
2029	$1,092
2030	$1,232
2031	$1,270
2032	$1,434
2033	$1,459
2034	$1,497
2035	$1,512
2036	$1,534
2037	$1,421
2038	$1,445
2039	$1,497
2040	$1,518
2041	$1,536
2042	$1,557
2043	$1,730

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 80: Total Financial Under **EWE** Sensitivity (Scenario 4 – SWER)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,315.4

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 4 – SWER dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 4 – SWER are $531,366.

Table 81: Curtailed Intermittent Energy, Annual MWh (Scenario 4 - SWER)

	Existing Wind	**Existing Solar**	**Generic Wind**	**Generic Solar**	**Total**
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,854	0	0	**5,854**
2027	0	3,378	0	0	**3,378**
2028	0	2,821	0	0	**2,821**
2029	0	2,193	0	0	**2,193**
2030	0	0	0	0	**0**
2031	0	0	0	0	**0**
RAP Total	**0**	**14,246**	**0**	**0**	**14,246**

Table 82: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 4 - SWER)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	258	4,515	20	1,061
2027	0	3,057	45	276
2028	114	2,275	16	416
2029	0	2,123	6	64
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**372**	**11,970**	**87**	**1,817**

The following table reflects PPA pricing, penalties, and taxes.

Table 83: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 4 - SWER)

	Wind ($)	Solar ($)
2024	$0	$0
2025	$0	$0
2026	$0	$216,270
2027	$0	$126,321
2028	$0	$106,117
2029	$0	$82,658
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$531,366**

Scenario 4 (SWER) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 84: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 4 - SWER)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2030	100	Wind + Battery		$2.88	
2034	100	Wind + Battery		$2.88	
2036	100	Wind + Battery		$2.88	
2038	100	Wind + Battery		$2.88	
2042	100	Wind		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2029	290	Gas	$1.50	$4.20	
2043	100	Solar		$2.88	
2043	100	Solar		$2.88	
2043	100	Solar		$1.68	
Wyoming (WYO) Transmission Area					
2040	100	Wind + Battery		$12.00	$109.00
2041	100	Wind		$4.20	
2041	100	Wind		$4.20	
New Mexico (NM) Transmission Area)					
2033	100	Wind		$2.88	$238.50
2033	100	Wind + Battery		$2.88	
2037	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 4 (SWER) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 85: Planning Reserve Margin, % Annual (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	35%	42%	46%	45%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 86: Loss of Load Probability, Hours (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 87: Expected Unserved Energy, Annual MWh (Scenario 4 - SWER)

2024	2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 4 - SWER)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario 4 – SWER, 50 MW of short duration storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 4 (SWER) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 88 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 88: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 4 – SWER)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 89 represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 89: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 4 – SWER)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and all Level II metrics were met.

Analysis of Market Purchases and Available Capacity (Scenario 4 – SWER)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
    - NM Market HE 2 to HE 6 and HE 11 to 15

    - 1 day in event no market depth
- Summer:
    - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
    - 1 day in event no market depth

In the EWE analysis for Scenario 4 – SWER, the market was used for 7.3 GWh in 133 hours during the January EWE events between 2026-2031. The market was used for 17 GWh in 99 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

5. Aggressive Colorado Emissions Reductions Scenario (ACER)

Assumptions unique to each scenario are identified in Attachment B-3.

Scenario 5 (ACER) – Expansion Plan, Retirements, System Mix, Capacity Factors, and Sales / Purchases

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, thermal unit capacity factors, and forecasted energy purchases and sales modeled for the scenario are shown below.

Table 90: Expansion Plan (Scenario 5 - ACER)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Solar[112]	West Colorado	140	1	140
2029	Wind/Battery	East Colorado	100	1	100
2030	NGCC with CCS[113]	West Colorado	290	1	290
2031	Wind/Battery	Wyoming / W. Neb.	100	1	100
2033	Wind	East Colorado	100	2	200
2035	Wind/Battery	East Colorado	100	1	100
2037	Wind/Battery	East Colorado	100	1	100
	Wind/Battery	New Mexico	100	2	200
2040	Wind/Battery	Wyoming / W. Neb.	100	2	200
	Solar – Build Transfer	West Colorado	100	2	200
2042	Wind/Battery	East Colorado	100	4	400
	Wind/Battery	Wyoming / W. Neb.	100	3	300
2043	Wind/Battery	Wyoming / W. Neb.	100	1	100
	Solar	New Mexico	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region:[114]

- All plans include applicable Colorado energy efficiency targets in base assumptions.[115]
- Low New Mexico Energy Efficiency was selected in the expansion plan of Scenario 5 – ACER in 2040.
- Low Wyoming Energy Efficiency was selected in the expansion plan of Scenario 5 – ACER in 2040.

[112] This resource is not a modeling selection, it is replacement project for Coyote Gulch PPA that was terminated in 2023.
[113] NGCC installed in 2030 and CCS conversion startup anticipated in 2031.
[114] Commission Rule 3605(c)(I)(I).
[115] 2020 ERP Settlement Agreement at Section 3.11.6.

The expansion plan also included the following Demand Response (DR) levels by region:[116]

- All plans include Colorado demand response required target of 4% beginning in 2025 per the 2020 ERP Settlement Agreement in base assumptions.[117]
- 52 MW of Wyoming Demand Response was selected in the expansion plan of Scenario 5 - ACER in 2038
- 84 MW of New Mexico Demand Response was selected in the expansion plan of Scenario 5 – ACER starting in 2042.

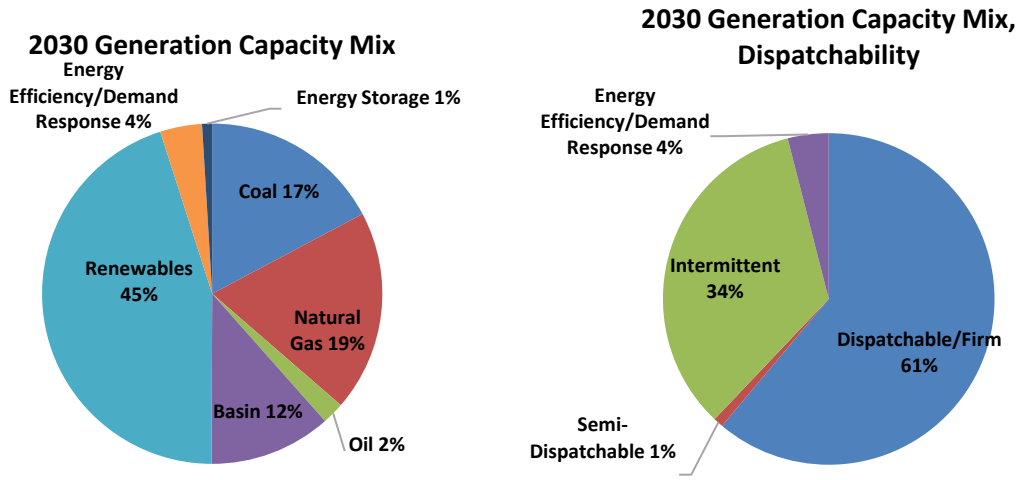
Unit retirements selected in the modeling are shown in the following table.[118]

Table 91: Modeled Retirements (Scenario 5 - ACER)

Unit	MW	Technology	Date
Craig 3	448	Coal	1/1/2028
Springerville 3	419	Coal	1/1/2037
LRS 2 (TS portion)	241	Coal	1/1/2042

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 8: Projected Tri-State System Resource Mix 2030 (Scenario 5 - ACER)[119, 120, 121]



[116] Commission Rule 3605(c)(I)(I).
[117] 2020 ERP Settlement Agreement at Section 3.11.8.
[118] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners").
[119] "Renewables" category reflects wind and solar resources, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[120] Capacity Mix charts reflect net capacity of system generation, before any application of ELCCs.
[121] System Energy Mix reflects sales to Members and non-Members.

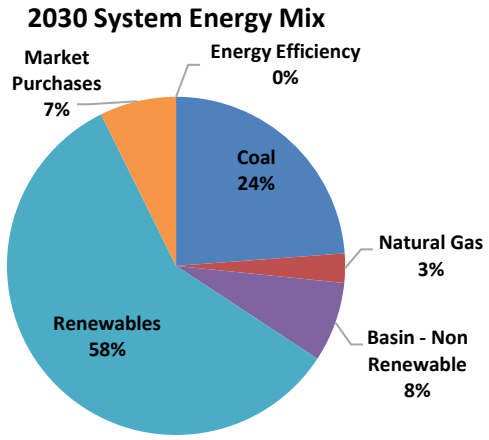


Table 92: Projected Annual Capacity Factors for Thermal Resources (Scenario 5 - ACER)

Thermal Resource	2024	2025	2026	2027	2028	2029	2030	2031
Craig 1	80%	16%	0%	0%	0%	0%	0%	0%
Craig 2	98%	9%	17%	4%	9%	0%	0%	0%
Craig 3	79%	14%	15%	11%	0%	0%	0%	0%
LRS 2	93%	89%	86%	78%	75%	71%	69%	69%
LRS 3	75%	64%	55%	48%	43%	40%	40%	45%
SPV 3	72%	67%	43%	42%	42%	36%	44%	43%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%
Limon	1%	0%	0%	0%	0%	0%	0%	0%
Pyramid	2%	1%	0%	0%	0%	0%	0%	0%
Shafer	24%	11%	1%	1%	1%	1%	0%	0%
GG-300-1x1-7FA05-CCS-wco	0%	0%	0%	0%	0%	0%	16%	49%

Energy sales and purchases forecasted, based on the modeling, are shown below.

Table 93: Forecasted Energy Sales and Purchases (Scenario 5 – ACER)

Scenario Forecast	2024	2025	2026	2027	2028	2029	2030	2031
Sales (GWh)	3,508	1,506	2,719	2,521	2,453	2,347	2,911	3,587
Purchases (GWh)	352	946	641	985	803	854	1,020	776

Scenario 5 (ACER) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the scenario are provided below.

Table 94: Environmental Impact - System Wide (Scenario 5 - ACER)[122]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2024	15,841,198	7,764	10,744	0.0383	704	6,774,266,318	32,133
2025	10,919,154	5,447	6,450	0.0245	513	4,099,792,207	19,995
2026[123]	8,046,894	4,781	5,543	0.0211	393	3,336,852,935	16,657
2027	7,524,321	4,471	5,149	0.0187	359	2,957,263,352	15,143
2028	6,758,931	4,045	4,479	0.0164	340	2,603,401,641	13,418
2029	6,279,584	3,827	4,253	0.0150	303	2,351,374,862	12,230
2030	5,720,642	3,969	4,393	0.0154	340	2,617,482,127	13,065
2031	5,621,064	3,993	4,418	0.0159	364	3,205,678,404	13,331
2032	5,229,420	3,827	4,281	0.0147	330	2,990,089,809	12,392
2033	5,542,856	3,963	4,395	0.0157	357	3,162,785,437	13,164
2034	5,600,099	3,999	4,444	0.0158	359	3,185,362,689	13,291
2035	5,341,998	3,895	4,362	0.0153	335	3,057,746,388	12,644
2036	4,976,911	3,771	4,291	0.0144	297	2,858,196,567	11,765
2037	3,872,884	3,313	3,900	0.0123	197	2,353,044,102	8,984
2038	3,889,235	3,328	3,924	0.0123	197	2,350,104,263	9,021
2039	3,958,518	3,372	3,983	0.0125	199	2,378,852,575	9,176
2040	3,928,034	3,352	3,944	0.0125	200	2,381,909,167	9,114
2041	3,954,875	3,371	3,977	0.0125	199	2,380,272,599	9,172
2042	2,550,838	2,573	3,064	0.0065	119	1,575,749,975	6,087
2043	2,537,465	2,577	3,059	0.0065	118	1,562,045,832	6,084
Total	**118,094,923**	**79,640**	**93,054**	**0.316**	**6,224**	**58,182,271,249**	**256,864**
Pounds/Gallons per MWh[124]	816	0.55	0.64	0.000002	0.04	201	1.955

[122] Commission Rule 3605(c)(I)(H). All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[123] Load reduced due to partial requirements contracts in 2026 forward.

[124] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 95: Social Cost of Carbon Nominal Dollars – System Wide (Scenario 5 - ACER)

Year	Annual Social Cost of Carbon
2024	$1,391,188,757
2025	$995,703,293
2026	$762,481,386
2027	$740,668,558
2028	$690,004,358
2029	$664,696,921
2030	$627,713,272
2031	$639,644,830
2032	$616,992,472
2033	$677,908,422
2034	$709,833,808
2035	$701,607,194
2036	$677,161,912
2037	$545,789,145
2038	$567,589,551
2039	$598,133,480
2040	$614,409,701
2041	$637,343,954
2042	$427,991,342
2043	$439,003,933

Table 96: Social Cost of Methane Nominal Dollars – System Wide (Scenario 5 - ACER)

Year	Annual Social Cost of Methane
2024	$82,865,100
2025	$54,041,930
2026	$47,200,356
2027	$44,961,643
2028	$41,658,773
2029	$39,685,014
2030	$44,283,639
2031	$47,333,383
2032	$46,063,578
2033	$51,195,405
2034	$54,050,793
2035	$53,741,866
2036	$52,234,099
2037	$41,644,283
2038	$43,640,015
2039	$46,305,451
2040	$47,955,236
2041	$50,131,697
2042	$35,047,588
2043	$35,786,521

Table 97: Colorado GHG Emissions Reduction Percentages, Targets and Forecast (Scenario 5 - ACER)

Year	Target[125]	Forecast
2025	47%	47%
2026	60%	66%
2027	67.8%	73%
2028	74.2%	76%
2029	80.6%	82%
2030	87.1%	88%
2031	90%	91%

See Appendix D for detailed GHG emissions calculations for the scenario.

Scenario 5 (ACER) – Financial Analysis

The present value revenue requirement (PVRR), net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), and annual revenue requirement are shown below.

[125] Modified targets per stakeholder-requested scenario assumptions identified in Attachment B-3, but still meets GHG reduction targets in 2020 ERP Settlement Agreement Sections 3.3.4. and 3.3.5.

Table 98: Total Financial (Scenario 5 - ACER)

$, Millions	**Scenario PVRR** (2023 WACC 4.12%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Scenario PVRR inclusive of SCoC NPV**	**Scenario PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,208.2	$11,026.8	$758.1	$28,235.0	$28,993.1
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,635.9				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$623.0				

Table 99: Annual Financial (Nominal $) (Scenario 5 - ACER)

Year	**Total Annual Revenue Requirement ($, Millions)**
2024	$1,016
2025	$978
2026	$898
2027	$960
2028	$1,007
2029	$1,075
2030	$1,212
2031	$1,232
2032	$1,400
2033	$1,415
2034	$1,452
2035	$1,474
2036	$1,506
2037	$1,447
2038	$1,470
2039	$1,501
2040	$1,523
2041	$1,537
2042	$1,554
2043	$1,730

Financial analysis of the of the scenario under the extreme-weather event stress is provided below.

*Table 100: Total Financial Under **EWE** Sensitivity (Scenario 5 – ACER)*

Scenario PVRR ($, Millions) (2023 WACC 4.12%)
$17,180.6

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

Intermittent resource curtailments are minimal within the Scenario 5 - ACER dispatch, through 2031. In 2026, with the removal of 163 MW of partial requirements load, and the retirement of Craig 1, we begin to see more curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Thermal resources are backed down to minimum or taken offline if economical to do so prior to curtailments of other resources. Since existing solar resources are modeled with the ITC they do not have a PTC penalty associated with curtailment, and therefore the model is setup to select solar first for curtailments. Total financial curtailment costs over the RAP for Scenario 5 – ACER are $544,004.

Table 101: Curtailed Intermittent Energy, Annual MWh (Scenario 5 - ACER)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Total
2024	0	0	0	0	**0**
2025	0	0	0	0	**0**
2026	0	5,613	0	0	**5,613**
2027	0	3,345	0	0	**3,345**
2028	0	2,732	0	0	**2,732**
2029	0	2,955	0	0	**2,955**
2030	0	0	0	0	**0**
2031	0	0	0	0	**0**
RAP Total	**0**	**14,645**	**0**	**0**	**14,645**

Table 102: Seasonal Intermittent Resource Curtailments, Annual MWh (Scenario 5 - ACER)

	Winter	Spring	Summer	Fall
2024	0	0	0	0
2025	0	0	0	0
2026	85	4,447	20	1,061
2027	0	3,025	44	276
2028	25	2,275	16	416
2029	0	2,767	18	170
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**110**	**12,514**	**98**	**1,923**

The following table reflects PPA pricing, penalties, and taxes.

Table 103: Estimated PPA Curtailment Costs and Penalties, Real (2023) $ (Scenario 5 - ACER)

	Wind ($)	Solar ($)
2024	$0	$0
2025	$0	$0
2026	$0	$207,282
2027	$0	$125,001
2028	$0	$102,660
2029	$0	$109,061
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$544,004**

Scenario 5 (ACER) – Transmission Analysis

Forecasted interconnection and network upgrade expenses, including at the POI, resulting from the scenario are shown in the table below.

Table 104: Transmission Interconnection & Network Upgrade Expenses Real (2023) $ (Scenario 5 - ACER)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind + Battery		$2.88	
2033	100	Wind		$2.88	
2033	100	Wind		$2.88	
2035	100	Wind + Battery		$2.88	
2037	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
2042	100	Wind + Battery		$2.88	
Western Colorado (WCO) Transmission Area					
2030	290	Gas	$1.50	$4.20	
2040	100	Solar		$2.88	
2040	100	Solar		$2.88	
Wyoming (WYO) Transmission Area					
2031	100	Wind + Battery		$12.00	$109.00
2040	100	Wind + Battery		$4.20	
2040	100	Wind + Battery		$4.20	
2042	100	Wind + Battery		$4.20	$34.00
2042	100	Wind + Battery		$4.20	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2042	100	Wind + Battery		$4.20	
2043	100	Wind + Battery		$4.20	
New Mexico (NM) Transmission Area)					
2037	100	Wind + Battery		$2.88	$238.50
2037	100	Wind + Battery		$2.88	
2043	100	Solar		$1.68	

Scenario 5 (ACER) – Level 1 Reliability Analysis

Reliability of each scenario is assessed by evaluating metrics under Level 1 and 2 criteria and through qualitative analysis of intermittent resources' ability to serve load and assessment of market purchases assumed under the EWE stress.

Level 1 Reliability Metrics and Analysis

Level 1 reliability results are as follows.

Planning Reserve Margin

The following table provides the annual PRM forecasted.

Table 105: Planning Reserve Margin, % Annual (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
39%	35%	46%	43%	35%	31%	44%	47%

Loss of Load Hours

The following table provides the annual LoLH forecasted.

Table 106: Loss of Load Probability, Hours (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
1	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE forecasted.

Table 107: Expected Unserved Energy, Annual MWh (Scenario 5 - ACER)

2024	2025	2026	2027	2028	2029	2030	2031
2	0	0	0	0	0	0	0

Intermittent Resources Ability to Serve Load and Maintain Reliability (Scenario 5 - ACER)

Section 3.11.14. of the 2020 ERP Phase I Settlement Agreement requires an assessment of how intermittent resource additions under each scenario serve load and maintain reliability.

The ELCCs of intermittent resources have declined since the 2020 ERP, per the results of the ELCC Study (Attachment G-1) and ELCCs continue to decline with the addition of intermittent resources. In Scenario

5 – ACER, 100 MW of 4-hr storage and a 290 MW combined cycle resource are included within the RAP. These additions provide semi-dispatchable and dispatchable resources to replace the dispatchable resources retiring during the RAP and support integration of intermittent resources.

Scenario 5 (ACER) – EWE Level 2 Reliability Metrics and Analysis

Level 2 reliability results are as follows.

Table 108 represents any loss of load hours identified in the twelve EWE periods. Below hours do not exceed 12 periods (hours) per all 12 EWE periods, and do not show more than three periods in any one event year. There were 0 MWhs of unserved energy and 0 hours of loss of load in all years for the extreme weather sensitivity. There was sufficient capacity to cover load for all extreme weather hours.

Table 108: LOLH EWE Evaluation for <= 12 Periods for All EWEs and <= 3 Periods per Each EWE year (Scenario 5 - ACER)

Event (Season/Year)	Date	Hour
All EWE Periods	N/A	N/A

Table 109 represents any EUE identified by hour in the 12 EWE periods. Below EUE does not exceed 20% of hourly load in any hour.

Table 109: EUE Evaluation for <= 20% of Hourly Load During EWEs (Scenario 5 - ACER)

Event (Season/Year)	Date	Hour	EUE (MWh)	Hourly Load (MWh)	% Load	Unused TS Thermal Resource Availability
All EWE Periods	N/A	N/A	N/A	N/A	N/A	N/A

Tri-State also analyzed the post-RAP period EWE and, Level II metrics were not met in the latter part of the RAP for Scenario 5 – ACER. Scenario 5 – ACER did not meet Level 2 reliability metric thresholds:

- Six hours of LOLH in 2037 (which is beyond the three hours per year threshold); and
- Two hours of capacity lean on the market (which is beyond the zero-tolerance threshold), in the following hours and capacity amounts:
    - July 12, 2042 HE2, 40 MW; and
    - July 13, 2043 HE2, 29 MW.

Analysis of Market Purchases and Available Capacity (Scenario 5 – ACER)

Per Section 3.11.14 of the 2020 ERP Settlement Agreement, the "analysis will assume that reliability objectives will be satisfied using only Tri-State resources regardless of bilateral or organized market access."

The EWE modeling allows limited access to market purchases for energy use as follows:

- Winter:
    - NM Market HE 2 to HE 6 and HE 11 to 15
    - 1 day in event no market depth

- Summer:
    - ECO, WCO, WY Markets (coincident with WACM transitioning to SPP RTO) HE 2 to HE 13
    - 1 day in event no market depth

In the EWE analysis for Scenario 5 – ACER, the market was used for 6.4 GWh in 115 hours during the January EWE events between 2026-2031. The market was used for 12.5 GWh in 78 hours during the July EWE events between 2026-2031. The model dispatched with the market instead of a generation unit due to economics. Market purchases during these limited hours were confirmed to not lean on the market for capacity.

Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase I scenarios is provided below.

Environmental Analysis

The following tables identify each scenario's system-wide forecasted CO_2 and CH_4 emissions in 2025 and 2030.

Figure 9: Comparison of Forecasted CO_2 Emissions in 2025 and 2030, by Scenario

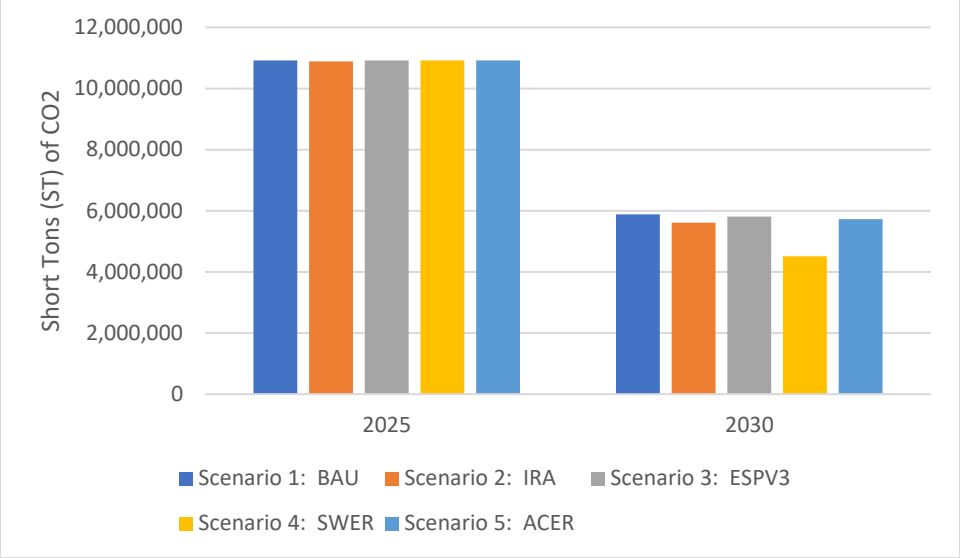
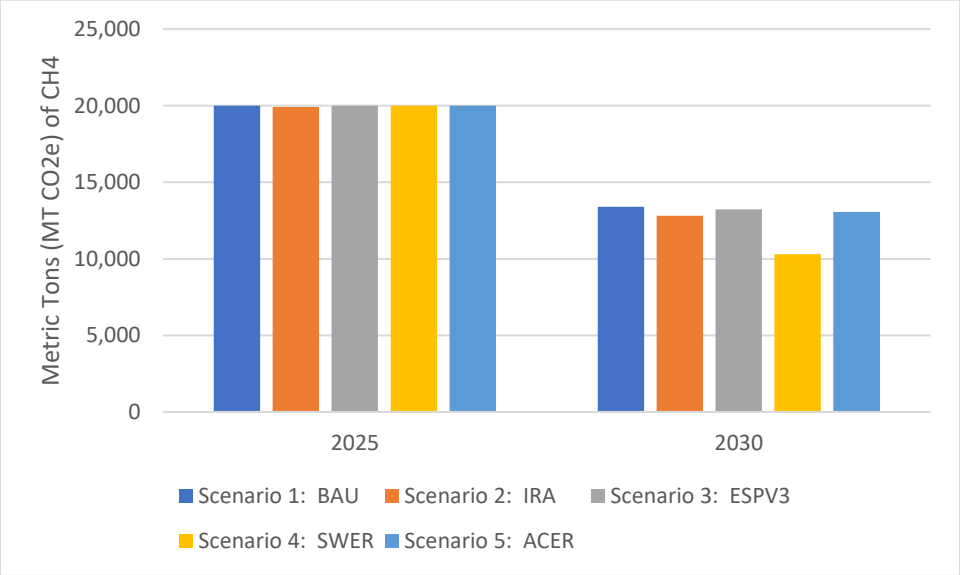


Figure 10: Comparison of Forecasted CH_4 Emissions in 2025 and 2030, by Scenario



The following table identifies each scenario's forecasted achievements toward Colorado GHG reduction targets. As shown in Figure 9 and Table 110, all scenarios achieve a consistent level of CO_2 and GHG reductions in 2025. The trend of similar GHG reductions across all scenarios holds for 2026 and 2027 as well, with the exception of Scenario 5 (ACER) achieving slightly higher reductions earlier—a result of the underlying modeling input constraint requiring minimum emissions achievements for each year of the RAP (see Attachment B-3 of the ERP Report (LKT-1). Those underlying constraints on emissions for Scenario 5 (ACER) result in significant reductions in the capacity factors for Craig 2 and LRS 3 starting in 2026 and result in the new gas plant not being utilized until 2030. Market sales are also reduced during the RAP under Scenario 5 (ACER). Notably, Scenario 2 (IRA), achieves the highest GHG reduction by 2030, 89%, as compared to the other scenarios as show in Table 110 and Figure 11.

Additional discussion of Tri-State's consideration of the environmental results of the scenario analyses can be found in the Executive Summary; and in the Financial Analysis section below, which scenario identifies PVRRs with SCoC and SCoM.

Table 110: Comparison of Scenario Achievements Toward Colorado GHG Reduction Targets

	2025	2026	2027	2030
Scenario 1: BAU	47%	60%	68%	86%
Scenario 2: IRA	47%	60%	67%	89%
Scenario 3: ESPV3	47%	60%	67%	85%
Scenario 4: SWER	47%	60%	68%	82%
Scenario 5: ACER	47%	66%	73%	88%

Figure 11: Comparison of Scenario Achievements Toward Colorado GHG Reduction Targets

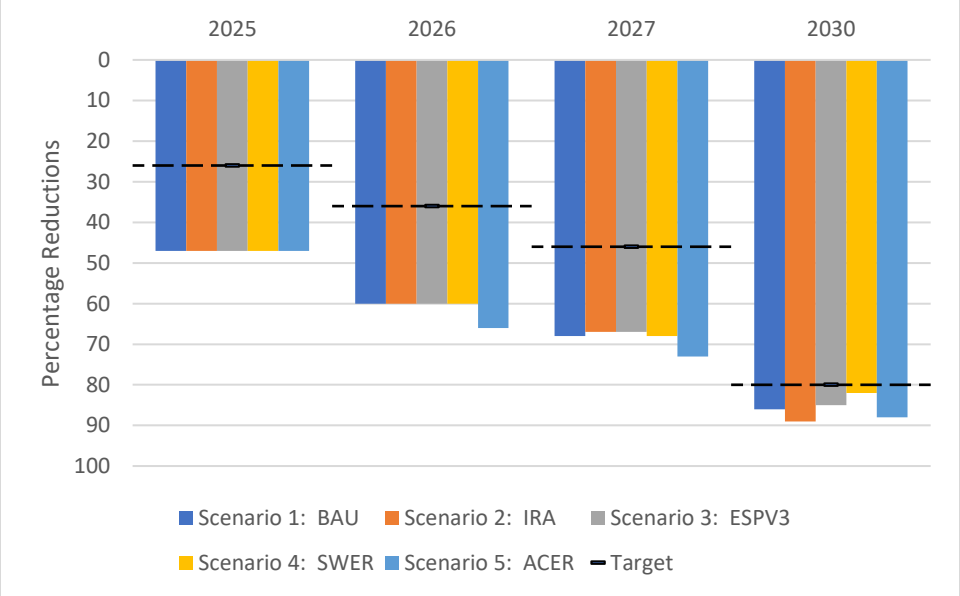
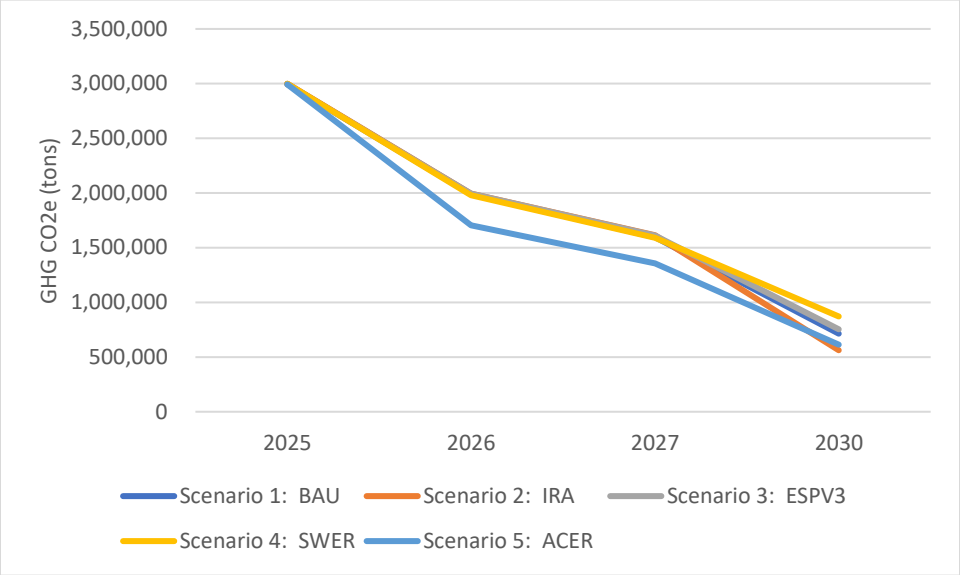


Figure 12: Comparison of Colorado CO2e



As shown in Figure 13 below, there is little deviation in the annual SCoC across the scenarios modeled, until after 2030. Scenario 1 (BAU) and Scenario 5 (ACER) have fairly similar SCoC levels in the early 2030s as Colorado greenhouse gas reduction levels are similar (roughly a 2 percent difference) in 2030; and from 2024 to 2033 the primary differences between the two scenarios being the timing of new resource additions. Neither Scenario 1 (BAU) or Scenario 5 (ACER) retires SPV 3 in the first ten years of the RPP. Scenario 2 (IRA) achieves a lower SCoC due to more renewable resources being added during the RAP, as well as the early retirement of SPV3. Scenario 3 (ESPV3) also results in lower levels of SCoC due to retirement of SPV 3 during the RAP. Scenario 4 (SWER) sets minimum system-wide emission reductions as underlying modeling input constraints, which result in the lowest SCoC levels across the scenarios. Similar trends across the scenarios are seen in Figure 14 below, for SCoM.

Figure 13: Comparison of SCoC

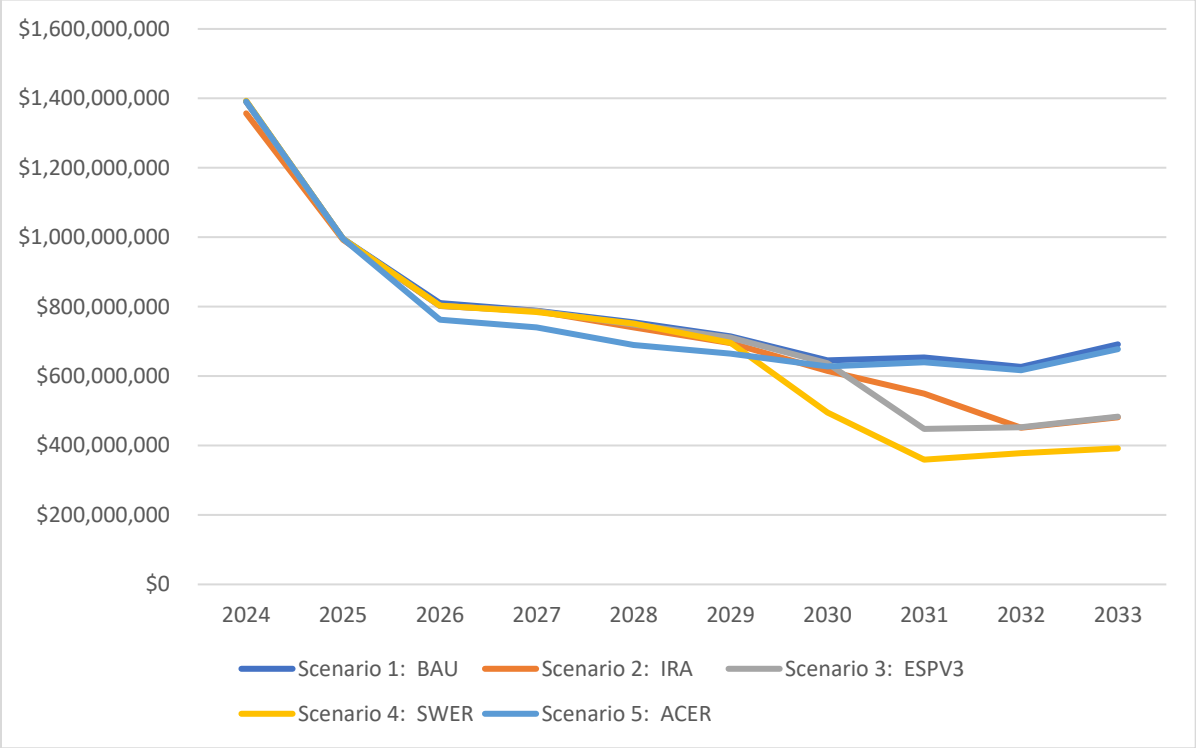
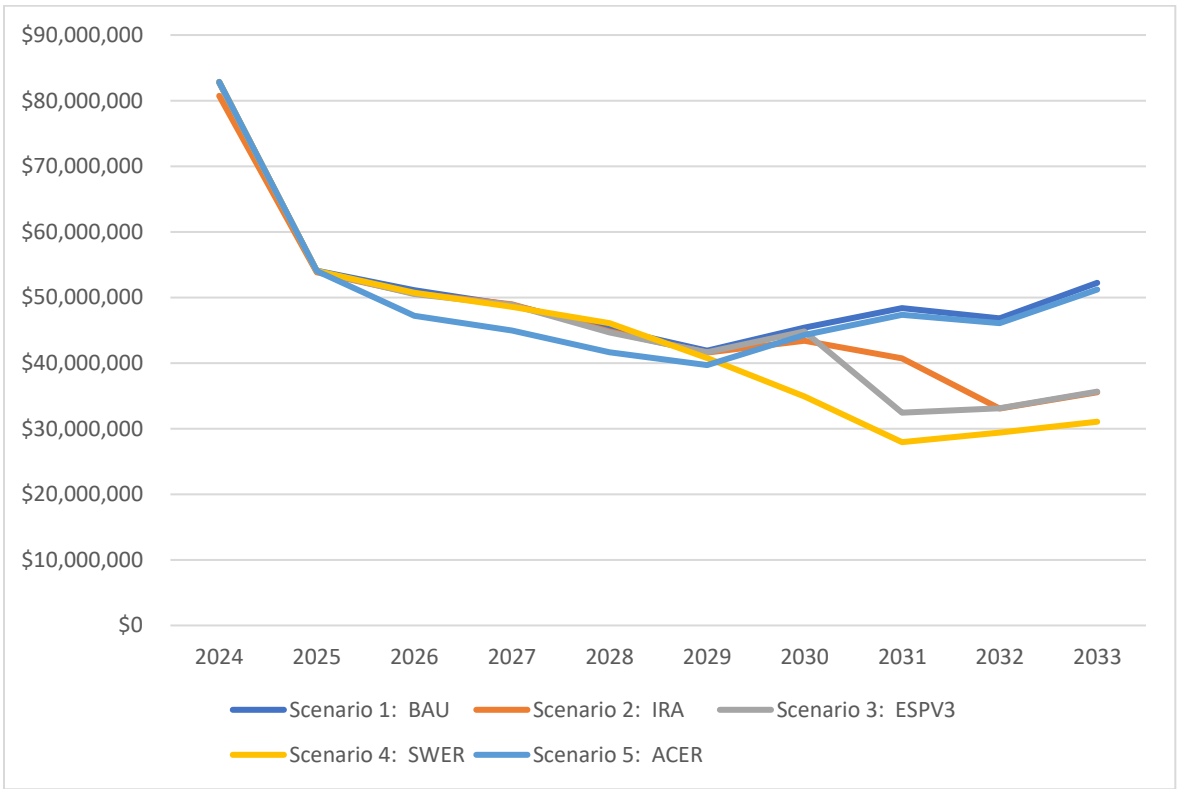


Figure 14: Comparison of SCoM



Financial Analysis

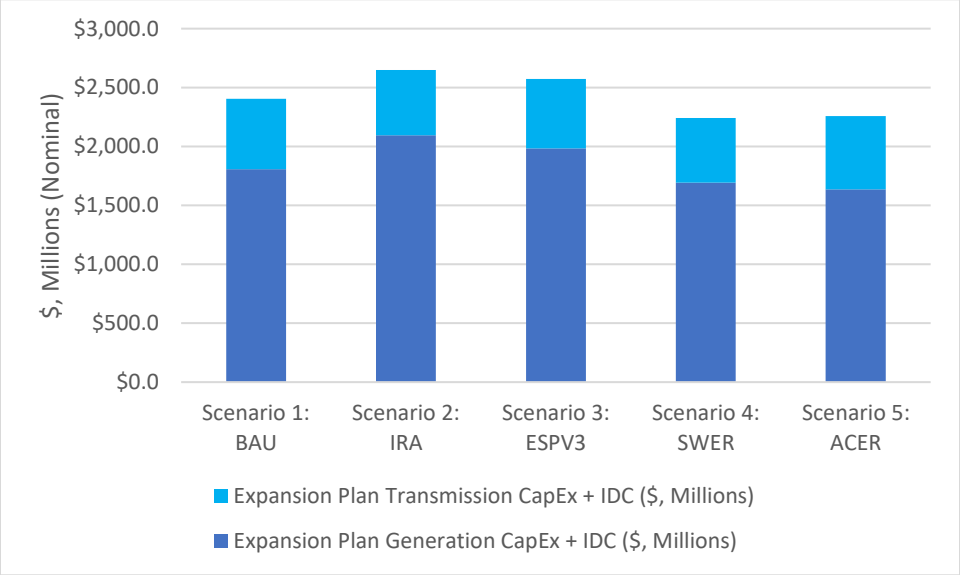
The following table compares total financial results for each scenario, both with and without the SCoC and SCoM. Scenario 2 (IRA) is one of the lowest cost plans on a PVRR basis, and has the lowest renewable curtailment costs during the RAP. Scenario 2 (IRA) exceeds Colorado GHG reduction target for 2030, while maintaining reliability and affordability—which best serves Tri-State Members.

Table 111: Comparison of PVRR

	PVRR ($, Millions)	PVRR w/SCoC and SCoM ($, Millions)
Scenario 1: BAU	$17,507.4	$29,916.4
Scenario 2: IRA	$17,221.4	$28,681.2
Scenario 3: ESPV3	$17,304.2	$28,828.6
Scenario 4: SWER	$17,343.9	$27,922.2
Scenario 5: ACER	$17,208.2	$28,993.1

Figure 15 below compares capital expenditures for resource additions and transmission interconnection and upgrades by scenario over the RPP. While the Scenario 2 (IRA) results in comparatively higher CapEx, the overall financial impact of the scenario is the lowest due to New ERA funding being pursued by Tri-State for the benefit of its Members.

Figure 15: Comparison of Generation and Transmission CapEx (Nominal $)



As shown in Table 112 below, all scenarios selected a 290 MW gas plant during the RAP (in 2028, 2029, or 2030), with conversion to CCS in 2031, and selected some amount of wind hybrids. All scenarios include 140 MW of solar to replace the Coyote Gulch PPA that was terminated in 2023. Scenario 1 (BAU) and Scenario 3 (ESPV3) have similar levels of MWs and resource additions during the RAP. Scenario 4 (SWER)

and Scenario 5 (ACER) have similar levels of MWs and resource additions. Scenario 2 (IRA) selects 1,400 MW of resources during the RAP, in addition to the 140 MW of replacement solar, more than double the total resource additions in Scenario 4 (SWER) and Scenario 5 (ACER) and significantly higher than the total resource additions in Scenario 1 (BAU) and Scenario 3 (ESPV3). The increase in resource selection during the RAP in Scenario 2 (IRA) is due to potential federal funding being available only through the RAP period. The funding would allow Scenario 2 (IRA) to bring on more resources during the RAP while improving affordability, maintaining reliability, and making strides toward evolving environmental requirements.

Table 112: Comparison of MW Additions by Scenario, by Technology over the RAP

	Scenario 1 – BAU	Scenario 2 – IRA	Scenario 3 – ESPV3	Scenario 4 – SWER	Scenario 5 – ACER
Wind	0	500	0	0	0
Solar	140	240	140	140	140
Standalone Storage	100	210	200	0	0
Gas	290	290	290	290	290
Wind Hybrid	300	200	300	100	200
Wind Hybrid – Battery Storage Component	150	100	150	50	100
RAP Total	**980**	**1,540**	**1,080**	**580**	**730**

Note: Wind Hybrid components share interconnect.

Table 113 below identifies the percentage of generation capacity that is intermittent or dispatchable/firm, and the percent of system energy that is renewable for each scenario in 2030. Scenario 2 (IRA) yields the highest percentage of renewables in terms of system energy mix in 2030, while maintaining a reasonable mix of intermittent and dispatchable/firm capacity at 39 percent and 54 percent, respectively.

Table 113: Comparison of Renewables, Intermittent and Dispatchable Resources in the 2030 Mix, by Scenario

	2030 Generation Capacity Mix, % Intermittent	2030 Generation Capacity Mix, % Dispatchable/Firm	2030 System Energy Mix, % Renewables
Scenario 1: BAU	34%	59%	59%
Scenario 2: IRA	39%	54%	64%
Scenario 3: ESPV3	34%	61%	58%
Scenario 4: SWER	33%	61%	61%
Scenario 5: ACER	34%	61%	58%

Note: Capacity from energy efficiency / demand response and semi-dispatchable resources are not reflected in either the intermittent or dispatchable/firm, therefore the sum of the capacity mix percentages does not total 100%.

Curtailments

The following tables identify the annual PPA curtailment costs (pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type.

Table 114: Comparison of Wind PPA Curtailment Costs by Scenario, Real (2023) $

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
2024	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0
2026	$0	$0	$0	$0	$0
2027	$0	$0	$0	$0	$0
2028	$0	$0	$0	$0	$0
2029	$0	$0	$0	$0	$0
2030	$0	$0	$0	$0	$0
2031	$0	$8,765	$2,511	$0	$0
RAP Total	**$0**	**$8,765**	**$2,511**	**$0**	**$0**

Table 115: Comparison of Solar PPA Curtailment Costs by Scenario, Real (2023) $

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
2024	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0
2026	$208,078	$2,816	$208,309	$216,270	$207,282
2027	$125,060	$0	$124,914	$126,321	$125,001
2028	$102,674	$9,596	$102,651	$106,117	$102,660
2029	$82,738	$122,947	$82,570	$82,658	$109,061
2030	$0	$29,692	$0	$0	$0
2031	$0	$329,902	$0	$0	$0
RAP Total	**$518,550**	**$494,953**	**$518,444**	**$531,366**	**$544,004**

Scenario 4 (SWER) and Scenario 5 (ACER) have the highest curtailment costs compared to the other scenarios. Scenario 2 (IRA) has the lowest curtailment costs while still achieving the highest GHG reduction in Colorado by 2030.

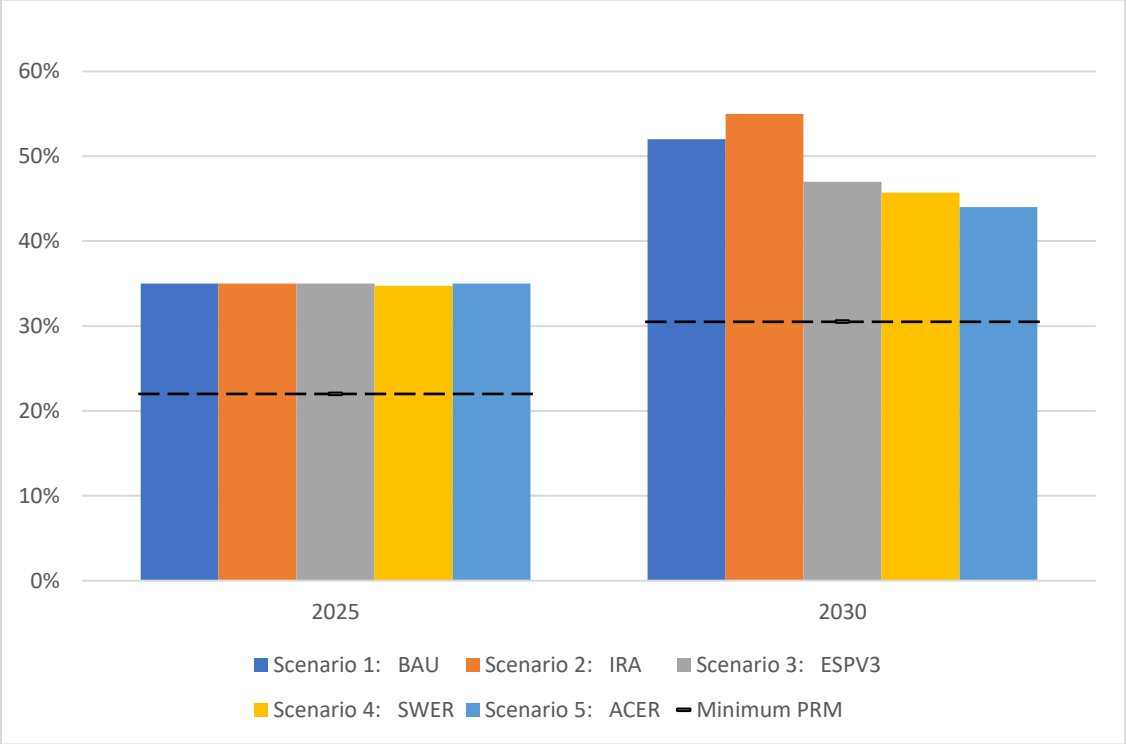
Table 116: Comparison of Total Wind + Solar Curtailment Costs during the RAP, by Scenario, Real (2023) $

	Scenario 1: BAU	Scenario 2: IRA	Scenario 3: ESPV3	Scenario 4: SWER	Scenario 5: ACER
RAP Total	$518,550	$503,718	$520,955	$531,366	$544,004

Reliability Analysis

PRMs were relatively consistent across all scenarios through 2027. PRMs in 2030 range from 44 percent to 55 percent. The level of resource additions enabled by potential New ERA funding in Scenario 2 (IRA) resulted in higher PRMs during the RAP as compared to other scenarios.

Figure 16: Comparison of PRMs During the RAP



Each of the scenarios were able to meet Level I and II reliability metrics during the RAP. Scenario 2 (IRA) is the scenario that results in the greatest certainty in achieving reliability in the most cost-effective manner because it allows for the acquisition of more resources earlier in Tri-State's planning period. Tri-State's PRMs stay well above requirements, allowing for potential procurement or operational delays to more likely be addressed without reliability issues.

Conclusion

Given the comprehensive and thorough data obtained on the multiple scenarios modeled, the ERP Report supports approval of the IRA Scenario as Tri-State's preferred plan. As such, Tri-State requests the Commission: (1) find that the IRA Scenario within Tri-State's ERP Application meets the applicable rule requirements, (2) approve the IRA Scenario as Tri-State's Phase I preferred plan, and (3) approve Tri-State's Phase II procurement plans in this proceeding.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-76:
Power Engineering Fabric Filters Article

Real World Performance Results of Fabric Filters on Utility Coal-Fired Boilers

www.power-eng.com/environmental-emissions/real-world-performance-results/

August 1, 2012

By Tim Stark, Sales Applications Engineer, GE Energy Air Filtration

Fabric filters, or baghouses, have been used to capture particulate from combustion processes for more than 50 years. They grew popular in the power generation industry in the 1970s after the first installation of a reverse-air-style fabric filter. Pulse-jet, another type of fabric filter, was also implemented on coal-fired power generation applications in the early 1970s, with the first actual utility installation taking place in the early 1990s.

Reverse-Air Style Fabric Filter

Reverse-air was the original style of choice for dust collection in utility applications. In the 1970s, this style of collector was more suited for utility applications than pulse-jet because of the proven relatively low air-to-cloth/offline cleaning technology.

- Reverse-Air Technology
- Air-to-cloth ratio target: 2.5:1 or lower
- Large footprint
- Offline cleaning
- Woven fiberglass fabric
- Finish options: Teflonâ„¢ B, acid resistant, expanded polytetrafluoroethylene (ePTFE) membrane
- Dust collected on inside of filter-no support cage utilized
- Average bag life range: 5-10 years

Pulse-Jet-Style Fabric Filter

The pulse-jet-style fabric filter, while in service since the early 1970s on coal-fired applications, was not yet cost-effective enough and did not have the performance track record nor the technology advancements required to operate at the scale of a large utility boiler application. As technology advanced and performance objectives were proven on smaller-scale industrial boiler applications, the pulse-jet technology gradually became the choice on utility installations.

Pulse Jet Technology

- Air-to-cloth ratio target: 3.5:1 or lower
- Smaller footprint
- Online cleaning with ability for offline cleaning
- Fabric options: woven fiberglass, polyphenylene sulfide (PPS) felt, acrylic felt, P84â„¢ felt, aramid felt, fiber blends
- Finish options: acid resistant, singe, Teflon coatings, micro-denier, ePTFE membrane
- Dust collected on outside of filter
- Support cage utilized
- Average bag life range: 3-6 years

Lab vs. Real-World Conditions

While a fabric filter serves to remove particulate from the gas stream prior to the stack, it must do so while also controlling the fabric filter pressure drop so that there is proper ventilation during combustion and the cost of maintenance and fan energy consumption are minimized. This is a relatively simple task under conditions typically found in the lab.

Lab conditions

- Constant temperature
- Constant volume
- Constant moisture level
- Constant gas stream chemistry
- Constant grain loading

Using the above criteria for a gas stream in the laboratory yields acceptable performance results for most fabric and finish options. The real world has more challenging criteria for a fabric filter.

Real-world conditions

- Temperature: ranges from ambient to over 400 degrees Fahrenheit, depending on the scrubbing technology before the fabric filter
- Volume: dependent on load and temperature
- Moisture level: dew point excursions, tube leaks, fire suppression system upsets, door seal leakage, scrubber system upsets
- Gas stream chemistry: fuel changes, scrubber system upsets, ammonia levels when SCR technology is used, carbon present when activated carbon injection is used
- Grain loading: uneven gas stream distribution, material handling system upsets, fuel changes, offline cleaning

It is most important for the fabric filter to maintain pressure drop in an acceptable range, while also meeting emissions requirements, under all of the typical operating conditions that occur. Meeting these goals and doing it cost effectively boils down to dust-cake

management.

Standard Fabrics Used in Utility Coal-Fired Boiler Applications 1

	Acrylic	PPS	Aramid	Fiberglass	P84	Pleated elements
Max Operating Temp	265 F	375 F	400 F	500 F	500 F	Dependent on base fabric
	130 C	190 C	204 C	260 C	260 C	
Concerns in coal fired boiler applications	Lowest maximum operating temperature.	Susceptible to degradation at elevated temperatures coupled with oxygen levels over 12%.	Not as capable as PPS in chemically active gas stream environment.	Woven style fabric that is more fragile than other options. Requires tight tolerance to be maintained on bag-to-cage fit in pulse jet applications.	Dimensional stability at higher temps over 400 F. Requires oversizing of filter to maintain proper bag-to-cage fit.	Air to cloth ratio must be below 3.5 to 1. Applicable only when additional cloth area is needed to lower air to cloth ratio and eliminate inlet abrasion.
Relative Cost	$	$$$	$$$	$$	$$$$	$$$$$
Fabric treatments to improve performance	**ePTFE Membrane:** Laminated to collection surface-most efficient option, enables fabric to handle system upsets reviewed in paper at more consistent airflow/less cleaning frequency.					
	Micro-denier fibers/Tri-lobal fibers: Creates improved efficiency over standard fibers by increasing total fiber surface area. Limited improvement over ability to handle upset conditions reviewed.					
	PTFE Coating: Non-membrane surface coating used to improve dust cake release-sacrifices ability to maintain consistent airflow leading to increased cleaning frequency/high differential pressure.					
	Singe: Removes some of the fabric surface area, creating an improved ability of the fabric to release dust cake. Limited improvement over ability to handle upset conditions reviewed.					

Dust-Cake/Emissions Management

Over time, a dust-cake develops on the surface of the filtration media as a result of the particulate in the gas stream. In a coal-fired boiler, for example, this dust would consist of fly ash and any materials used to treat the gas stream (lime, trona, powder-activated carbon, etc.) before it collects on the fabric filter. This dust-cake is controlled by the baghouse cleaning system. The dust-cake performs two critical functions in the baghouse:

1. Filtration efficiency: The fabric filter acts as a support structure for a dust-cake that actually creates and controls efficiency. The fabric itself is not as efficient as the dust cake that is created on its surface, and the fabric alone cannot allow the system to meet environmental regulations. This dust-cake also provides some protection against the incoming gas stream, keeping the fabric from being directly subjected to the incoming dust load.

2. Gas-stream contact with dust-cake: In a coal-fired boiler that uses scrubber technology or activated-carbon injection technology before the baghouse, the dust-cake on the filter is providing some of the contact time between the gas stream and the materials injected into the gas stream for pollution control.

Common Upsets Causing Fabric Filter Issues 2

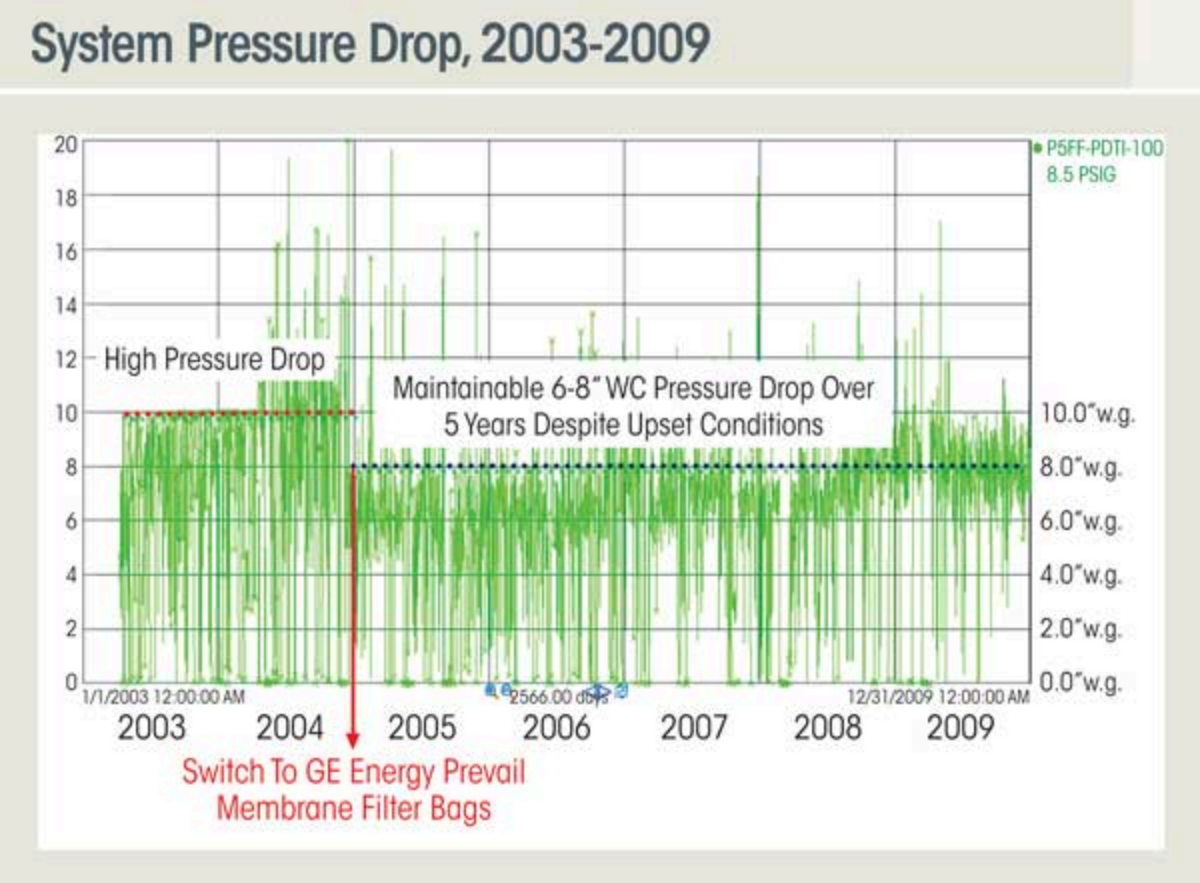
Upset Condition	Fabric Filter Effects
Tube leaks	High pressure drop from moisture carry-over, leading to constant cleaning
Material handling system failure	High hopper levels leading to high pressure drop from re-entrainment and filter abrasion/failure-also potential for heat excursion from hopper fires
Cleaning system failure	High pressure drop
Dew point excursions from pre-fabric filter equipment failure	High pressure drop from moisture condensation and chemical degradation of fabric/premature corrosion of support cages in pulse-jet-style units
SCR system upsets leading to high ammonia slip	High pressure drop from sticky dust created by ammonia levels, leading to constant cleaning
Fire suppression system failure	High pressure drop from moisture carry-over, leading to constant cleaning

The key to controlling this dust-cake is monitoring the pressure drop and controlling the cleaning to maintain the dust-cake.

Over-cleaning filter bags is one of the main causes of premature bag failure. First of all, the filter has the ability to withstand a certain number of cleaning cycles over the course of its life. If we clean a filter every five minutes, it may last two years. If we clean it every 10 minutes, it may last four years. The cleaning energy will slowly degrade the filter much like cleaning fabric in a washing machine will degrade clothing over time. The less we clean, the longer the fabric should last. The other problem with over-cleaning is it does not allow a dust-cake to properly develop, leading to either dust penetrating into the depth of the fabric and becoming permanently lodged there (blinding) or the dust passing completely through the fabric and ending up as emissions (bleed-through). Most people intuitively believe that the more they clean the filters, the lower the pressure drop and the lower the potential for emissions, but the opposite is true: it is the dust-cake that provides the efficiency and protects the fabric from premature blinding and/or bleed-thru.

In a utility baghouse, with gas stream treatment equipment upstream of the baghouse, the dust-cake has another purpose: create more contact time between the gas stream and the dust to help scrub the gas stream. This is an important variable to note. When trying to improve the filter's ability to release dust-cake, we often consider other fabric finishes. This raises the question about degrading the scrubbing results with filters that can potentially

operate at a lower overall pressure drop. Can we improve dust-cake release to the point where it adversely affects the scrubbing characteristics of the dust-cake? Real-world results show that the fabric finish does not necessarily affect the filter's ability to create the dust-cake needed to accomplish scrubbing goals. Dust-cake management, regardless of the fabric finish used, continues to be the important factor when operating a power plant baghouse.



Effects on Dust-Cake Management of Gas Stream Treatment

The air pollution control equipment used in today's coal-fired utility plants will almost always consist of more than just a fabric filter. Various different gas stream treatment technologies are used either before or after the fabric filter to treat the gas stream before it leaves the stack. Not only does this equipment have the potential to affect the performance of the fabric filter, the fabric filter can also affect this equipment.

To maintain a lower pressure drop for a longer period of time with the lowest cleaning frequency possible, end users have chosen different fabric types and fabric finishes. The gas stream treatment equipment used in conjunction with fabric filters can create conditions that make it more challenging for the cleaning system to maintain pressure drop. There are several instances where the fabric style or finish has been successfully changed in order to

improve a system's ability to maintain pressure drop in the correct range with the lowest cleaning frequency possible. The most successful example in recent years has been the treatment of the base fabric with an expanded polytetrafluoroethylene (ePTFE) membrane. In brief, the membrane creates a very slick and highly efficient surface that allows the dust-cake to be maintained with less cleaning energy. This helps the system not only handle a sticky, difficult-to-clean dust-cake, it decreases cleaning frequency (leading to longer filter life). The gas stream treatment options listed below all have an effect on the dust-cake that the fabric filter handles. Several of the case studies discussed below will show results with standard filtration media and results after switching to the ePTFE membrane option.

While ePTFE filters enable the fabric filter to run at a lower pressure drop regardless of the changes in gas stream, the real-world results show that they do not adversely affect the scrubbing results from the potential decrease in contact between the gas stream and the dust-cake.

Scrubbers

Scrubbers are used for flue gas desulfurization (FGD) and acid gas control. There are several different technologies used.

- Spray dry FGD-typically upstream of the fabric filter
- Wet dry FGD-typically downstream of the fabric filter
- Circulating dry scrubber
- Dry sorbent injection

Potential fabric filter effects:

- Increase in grain loading
- Potential for moisture introduction into fly ash, leading to high pressure-drop/increased cleaning requirements
- Potential for decreased inlet temperature, increasing the risk of the gas stream dropping below the acid dew point before or inside of the fabric filter
- When scrubber is downstream of fabric filter, inefficient operation can lead to increased cleaning requirements for downstream technology

Selective Catalytic Reduction (SCR)

SCRs are used to convert nitrogen oxides (NOx) with the aid of a catalyst into diatomic nitrogen (N2) and water. Typically ammonia is added into the flue gas stream and is absorbed onto a catalyst.

Potential fabric-filter effects:

Sticky dust created by ammonium bisulfate that leads to higher pressure-drop/increased cleaning frequency

Electrostatic Precipitators (ESPs)

ESPs remove particulate from the flue gas by using electrical forces. The dirty gas stream is passed through an electrical field set up between electrodes of opposite polarity. In the utility industry, where ESPs were originally installed as the primary Air Pollution Control device, they sometimes are left in service after the addition of a fabric filter downstream from the ESP.

Potential fabric filter effects:

- Lower grain loading — a good thing — leads to potentially lower cleaning frequency
- Potential for applying fabric filter at a higher A/C ratio based on lower grain loading
- Can change the particle size distribution going to the fabric filter, removing the larger particulate and allowing mostly the finer particulate to pass through. This can create a more challenging dust-cake for the baghouse

Carbon Injection

One method to help control mercury emissions is the injection of activated carbon into the flue gas to adsorb mercury before it exits the stack. This is typically done upstream of the fabric filter.

Potential fabric filter effects:

- Increased grain loading
- Fire potential
- Inability to sell fly ash from baghouse

Real-World Upset Conditions Affecting Fabric Filters

The fabric filter has several jobs to perform in a coal-fired boiler application. It needs to maintain pressure drop while meeting all environmental regulations in conjunction with the other pieces of environmental equipment in the system. On top of that, upset conditions in the real world can present challenges to the fabric filter. If the fabric filter can’t handle the upsets, the result could lead to the plant not being able to run at the required load demand or being forced to shut down because of an inability to meet environmental regulations. The other issue is if the upset conditions require continuous cleaning for prolonged periods of time, leading to premature bag failures and shorter bag life than the budget anticipates.

Case Study “A”

Problem: This power plant struggled with differential pressure levels with the original set of bags, which were made of a PPS base fabric with a Teflon surface coating. This included scrubber system upsets, ammonia slip over 10 ppm, fire suppression system upset, and pulsing system failure all leading to pressure-drop increases that were difficult to control even when pulsing at maximum psi levels and rapid pulse settings.

Additional Info: Case Study A	3
Cleaning style	Pulse-jet
APC train summary	SCR, spray dryer, fabric filter
MW	565 MW
Fuel	PRB
Average pressure drop at full load	7 inches wc
Fabric	Original: PPS with Teflon coating.
	Three-year life with dp struggles.
	Upgrade: PPS with ePTFE membrane. Six-year life at steady dp.
Average opacity	1 percent

Solution: GE Energy Preveil eTPFE membranes on PPS filters

Result: After three years, the original filters were replaced with GE Energy Preveil ePTFE on PPS filters. The system ran for more than five years at below 7 inches of pressure drop while again experiencing all of the upset conditions listed above. There was no change in the system’s scrubbing ability with the switch to membrane and no increase in lime usage. Cleaning pressure and frequency have both been decreased.

Case Study “B”

Problem: This location struggled with particulate bleed-through and blinding with the original set of PPS filters, leading to opacity and high pressure drop.

Solution: GE Energy Preveil ePTFE membranes on PPS filters.

Additional info: Case Study B	4
Cleaning style	Pulse-jet
APC train summary	Electrostatic precipitator-dry scrubber-baghouse
MW	250 MW
Fabric	Original: PPS. Two-year life with dp and opacity struggles.
	Upgrade: PPS with ePTFE membrane. Two years to date with steady dp and no opacity issues.
Average opacity	Two percent

Results: After three years, the original PPS filters were replaced with GE Energy Preveil ePTFE membrane on PPS filters. The plant has operated for two years with the new style filters without any bleed-through or blinding, and the pressure drop and opacity issues have been eliminated. There was no change in the system's scrubbing ability with the switch to membrane, and no increase in lime usage. Cleaning pressure and frequency have both been decreased.

Case Study "C"

Problem: While this reverse-air style unit achieves more than a nine-year life with the standard woven fiberglass filters, the challenge had been the high pressure drop levels over 9 inches and the annual expense of using a vac truck to vacuum out the clean air plenum. Every six months a crew would have to isolate each compartment and vacuum off the tube sheet because of the bleed-through of the fine particulate created in this system.

Additional info: Case Study C	5
Cleaning style	Reverse-air
APC train summary	Fabric filter, wet scrubber
MW	245
Fuel	Low-sulfur coal
Average pressure drop at full load	4 inches wc
Fabric	Original: woven glass, acid-resistant finish. Struggled to maintain 9-inch pressure drop. Sifting of ash through fabric led to quarterly project of vacuuming ash out of clean air plenum. Bags changed after eight years. Current: same base fabric with ePTFE membrane-after five years of operation, pressure drop maintained at 4 inches with cleaning typically triggered by three-hour timer versus upper pressure drop setting of 5 inches. Have not yet vacuumed clean air plenum since the installation of the membrane.
Average opacity	2 to 3 percent

Solution: GE Energy Preveil ePTFE membrane-treated woven fiberglass filters

Results: The original filters were replaced with GE Energy Preveil ePTFE membrane-treated woven fiberglass filters five years ago.

The pressure drop average dropped from 9 to 4.5 inches, and the expense of vacuuming off the tube sheet has been eliminated. The cleaning frequency has also been cut in half.

Case Study “D”

Problem: This unit struggled for the first two years with pressure drop over 9 inches. Offline cleaning methods were used to try to recover with limited success.

Solution: GE Energy Preveil ePTFE membrane on PPS filters

Additional info: Case Study B	6
Cleaning style	Pulse-jet
APC train summary	Dry scrubber-baghouse
MW	120
Fuel	Low-sulfur coal
Average pressure drop at full load	6 inches wc
Fabric	Original: PPS struggled with pressure drop over 9 inches, changed filters after three years.
	Current: PPS with ePTFE membrane, on year three with pressure drop averaging 6 inches with less cleaning frequency.
Average opacity	2 percent

Results: The original filters were replaced with ePTFE membrane on PPS filters. The pressure drop has averaged 6 inches after two years of operation. The current system is limited with regards to pulsing pressure and volume, so pulsing frequency and pressure are unchanged. There is no change in the system's scrubbing ability with the switch to membrane and no increase in lime usage.

Case Study "E"

Problem: This system struggled with 9-inch pressure-drop levels caused by a scrubber control issue that led to low inlet temperatures. Ammonia slip levels also caused a stickier dust-cake.

Solution: GE Energy Preveil ePTFE membrane on PPS filters

Additional Info: Case Study E	7
Cleaning style	Pulse-jet
APC train summary	SCR, dry scrubber, activated- carbon injection, baghouse
MW	790 MW
Fuel	Low-sulfur coal
Average pressure drop at full load	6 inches wc
Fabric	Original: PPS/P84 blend. High pressure drop struggles over 9 inches caused by ammonia bisulphate formation and low inlet temperatures. Changed filters at three years.
	Current: PPS with ePTFE membrane. Pressure drop averaging 6 inches after two years.
Average opacity	1 percent

Results: The original filters were replaced with GE Energy Preveil ePTFE membrane on PPS filters and, after two years, the pressure drop has been averaging 6 inches. The cleaning energy and frequency has been decreased. A year after the membrane filters were installed, the pulsing system had an upset condition allowing a very heavy dust-cake to develop on the filters. After the problem was solved with the pulsing system, the filters immediately recovered to normal pressure drop levels.

Case Study “F”

Problem: This system has always operated in the 9-inch pressure-drop range with continuous cleaning using standard woven fiberglass. The sizing of the unit is relatively aggressive.

Solution: GE Energy Preveil ePTFE membranes on woven fiberglass filters

Additional info: Case Study F	8
Cleaning style	Reverse-air
APC train summary	Dry scrubber-baghouse
MW	450 MW
Fuel	Low-sulfur coal
Average pressure drop at full load	7 inches wc
Fabric	Original: woven fiberglass with acid-resistant finish. Nine-inch pressure drop with continuous cleaning and a four-year life.
	Current: same base fabric with ePTFE membrane. Maintains 9-inch pressure drop with continuous cleaning and a six-year life.
Average opacity	2 percent

Results: After installing GE Energy Preveil ePTFE membrane on woven fiberglass filters, the unit still operates at 9-inch pressure drop, but the cleaning frequency has been decreased and the bag life has gone from four to six years. There was no change in the system's scrubbing ability with the switch to membrane and no increase in lime usage.

Case Study "G"

Problem: This reverse-air unit had challenges with efficiency, which led to ash buildup in the wet scrubber that required expensive pressure washing of the scrubber on a semi-annual basis.

Additional info: Case Study G	9
Cleaning style	Reverse-air
APC train summary	Baghouse-wet scrubber
MW	300 MW
Fuel	Low-sulfur coal
Average pressure drop at full load	6.5 inches wc
Fabric	Original: woven fiberglass with acid-resistant finish.
	Current: same base fabric with ePTFE membrane treatment.
Average opacity	2 percent

Solution: GE Energy Preveil ePTFE membrane-style

Results: Three years after installing GE Energy Preveil ePTFE membrane-style filters, the plant has not yet had to go through the wet-scrubber cleaning process.

Case Study “H”

Problem: This system struggled with 9-inch pressure-drop levels and opacity spikes above 5 percent with the original PPS-style filters.

Solution: GE Energy Preveil ePTFE membrane on PPS filters

Additional info: Case Study G	10
Cleaning style	Pulse-jet
APC train summary	SNCR, CFD, baghouse
MW	500 MW
Fuel	Low-sulfur coal
Average pressure drop at full load	6 inches wc
Fabric	Original: PPS struggled with 9-inch pressure drop and opacity spikes. Filters changed after 3.5 years.
	Current: PPS with ePTFE membranes, averaging 6-inch pressure drop and below2-percent opacity after 1.5 years.
Average opacity	Less than 2 percent

Results: After 3.5 years, GE Energy Preveil ePTFE membranes were installed on PPS filters. After 1.5 years since the GE filters were installed, the system has been averaging 6-inch pressure-drop and 2 percent or lower opacity levels, and the opacity spikes have been eliminated. There has been no change in the system's scrubbing ability with the switch to the membrane and no increase in lime usage.

Conclusion

Fabric filters utilized on coal-fired boilers face real-world environments that make their primary goals of managing pressure-drop, efficiency and a percentage of the systems scrubbing performance a challenge. Dust-cake management is critical in ensuring these goals are met. Multiple factors can have an impact on a system's dust-cake:

1. Low inlet temperatures
2. High moisture levels
3. Challenging dust-cake created when using scrubbers/SCRs/activated carbon injection
4. Longer-than-normal filter bags requiring aggressive cleaning to maintain pressure drop
5. Changes in ash volume and gas stream chemistry

Managing the dust cake requires controlling the filter differential pressure and is critical in ensuring:

1. Required particulate removal efficiency
2. Plant load requirements

3. Necessary scrubbing by dust-cake on filter media
4. Minimized energy cost for operating fabric filter

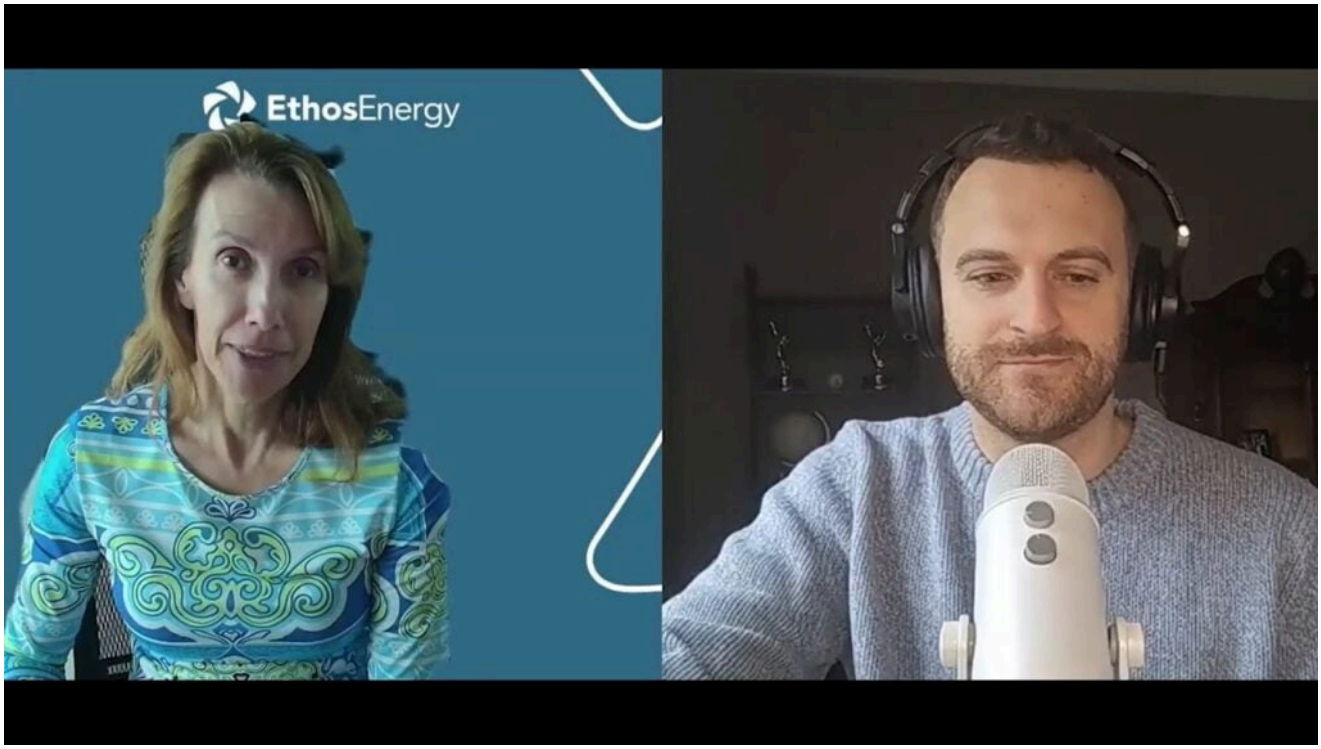
10. Maximized filter life with minimized maintenance costs

Filter media technology exists that improves the ability of the fabric filter to operate under real-world conditions. The use of ePTFE membrane laminated filters improves the performance of the fabric filter by allowing it to operate at a lower pressure drop and recover from common upset conditions.

Standard Fabrics Used in Utility Coal-Fired Boiler Applications
Environmental and EmissionsPE Volume 116 Issue 8

Must View





Inside EthosEnergy’s growth moment with CEO Ana Amicarella

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Sheep grazing gains ground in solar vegetation management

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-77:
Power Engineering Wet-Limestone Scrubbing Article

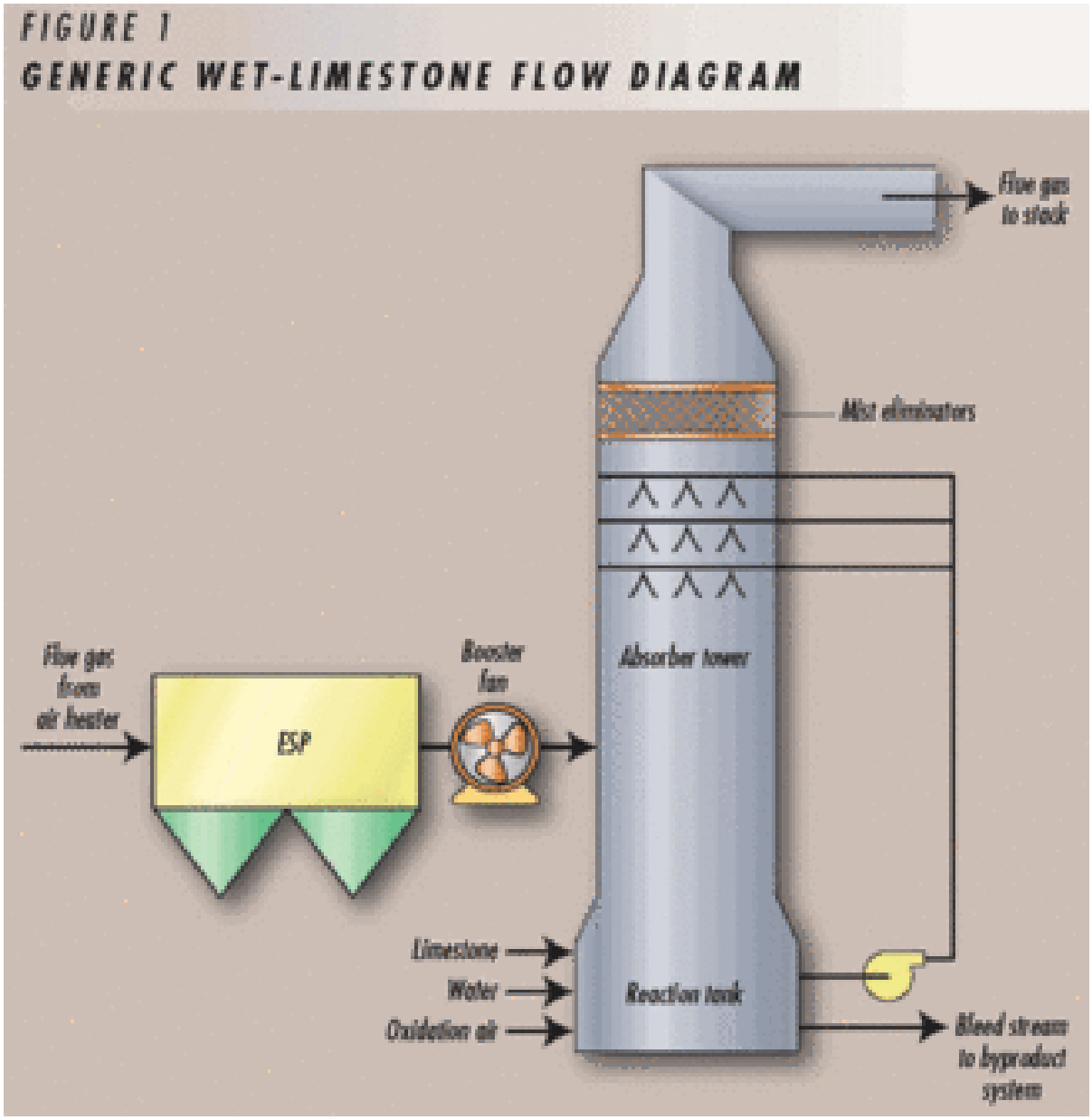
Wet-Limestone Scrubbing Fundamentals

www.power-eng.com/operations-maintenance/wet-limestone-scrubbing-fundamentals/

August 1, 2006

By Brad Buecker, Contributing Editor

Stricter environmental regulations are forcing many utilities to install flue gas desulfurization (FGD) systems to control sulfur dioxide (SO_2) emissions below levels that can be attained by burning Powder River Basin (PRB) coal alone. The choice for many applications is wet-limestone scrubbing, a proven technology. Startup of the new scrubbers, combined with the many workforce retirements that are coming or have already occurred, will force many new personnel to learn FGD details. Properly controlling chemistry in these systems is vital for issues such as scale control, good reagent utilization and corrosion prevention. This article examines important concepts of wet-limestone scrubbing.



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A generic wet-limestone flow diagram is outlined in Figure 1. (The diagram also applies for systems using hydrated lime-Ca(OH2)-as the reagent, where equipment and vessel sizes are smaller.) Wet-limestone scrubbing is a classic example of an acid-base chemistry reaction applied on a large industrial scale. Simply stated, an alkaline limestone slurry reacts with acidic sulfur dioxide. As flue gas passes through the scrubber and is contacted by the limestone slurry sprays, sulfur dioxide absorbs into the liquid. Theoretical chemists argue that sulfur dioxide forms only a hydrated compound, where individual SO2 molecules are surrounded by water. However, when SO2 is introduced to water, a pH depression occurs, where the following equilibrium reactions are representative:

SO 2 + H 2O â† â†’ H 2SO 3 â† â†’ H + + HSO 3– â† â†’ H + + SO 3 -2
Limestone, whose primary components are calcium carbonate (CaCO3) with lesser amounts of magnesium carbonate (MgCO3), when introduced to water will raise the pH according to the following mechanism.

CaCO 3 + H 2O â† â†’ Ca +2 + CO 3 -2 + H 2O â† â†’ Ca +2 + HCO 3– + OH –
However, CaCO3 is only very slightly soluble in water, so this reaction is minor in and of itself. In the presence of acid, calcium carbonate reacts much more vigorously. It is the acid generated by absorption of SO2 into the liquid that drives the limestone dissolution process.

CaCO 3 + 2H + â†’ Ca +2 + H 2O + CO 2 â†‘
Equations 1, 2 and 3 when combined illustrate the primary scrubbing mechanism.

CaCO 3 + 2H + + SO 3 -2 â†’ Ca +2 + SO 3 -2 + H 2O + CO 2 â†‘
In the absence of any other factors, calcium and sulfite ions will precipitate as a hemihydrate, where water is actually included in the crystal lattice of the scrubber byproduct.

Ca +2 + SO 3 -2 + ½H 2O â†’ CaSO 3 – ½H 2O â†“
However, oxygen in the flue gas has a major impact on chemistry and in particular on byproduct formation. Aqueous bisulfite and sulfite ions react with oxygen to produce sulfate ions (SO4-2).

2SO 3 -2 + O 2 â†’ 2SO 4 -2
Approximately the first 15 mole percent of the sulfate ions co-precipitate with sulfite to form calcium sulfite-sulfate hemihydrate [(CaSO3 – CaSO4) – ½H2O]. Any sulfate above the 15 percent mole ratio precipitates with calcium as gypsum.

Ca +2 + SO 4 -2 + 2H 2O â†’ CaSO 4 – 2H 2O â†“
Calcium sulfite-sulfate hemihydrate is a soft, difficult-to-dewater material that previously has had little practical value as a chemical commodity (although interest is beginning to develop in agricultural benefits of the material). For this reason, many scrubbers are equipped with forced-air oxidation systems to introduce additional oxygen to the scrubber slurry. A properly designed oxidation system will convert all of the liquid sulfite and bisulfite ions to sulfate ions. Sulfate, of course, precipitates with calcium as gypsum, which typically forms a cake-like material when subjected to vacuum filtration. In many cases 85 to 90 percent of the free moisture can be removed by this relatively simple mechanical process. Gypsum is the primary ingredient of wallboard. A number of FGD systems throughout the world produce wallboard-grade byproduct. (To read more about combustion by product markets, see the July 2006 issue of *Power Engineering*.)

Improvements

Problems that plagued first- and second-generation wet-limestone scrubbers included poor SO2 removal, scale formation in the scrubber vessels and poor utilization of the limestone reagent. Spray nozzle efficiency, scrubber vessel configuration, limestone reactivity and particle size are all factors that influence these processes.

Adequate mixing of the flue gas and slurry is critical. Early scrubber towers usually were equipped with internal packing or trays to enhance gas-liquid contact. While the theoretical concept behind these mixing devices was valid, the material would often become plugged with scale, necessitating periodic cleaning, replacement or laborious control methods.1 In some early designs, the packing consisted of plastic balls, which often would “cement” together and cause a degradation in scrubber performance. Spraying technology has greatly improved in the last few years and open spray towers are now becoming popular.2 Spray nozzle design is critical in these systems, as droplet size must be optimized to provide the best contact. The slurry spray pattern also must be such that channeling of the flue gas does not occur. (An excellent article on spray nozzle types may be found in reference 3.) A still-common technique is to introduce the flue gas in a tangential pattern to the scrubber tower. This imparts a centripetal motion to the gas and forces it to swirl around the tower as it passes upwards. The swirling action improves slurry-gas mixing and increases gas residence time in the vessel.

Limestone reactivity is another key factor. In general, limestones with 94 percent or greater calcium carbonate content provide suitable alkalinity for reaction. Impurities in the stone may cause significant operating difficulties. Magnesium, a common substitute for calcium, can be either helpful or harmful depending upon its chemical makeup within the stone. If the magnesium exists as homogenous magnesium carbonate (MgCO3), it can enhance SO2 removal by providing extra alkalinity to the scrubbing solution. However, magnesium often co-exists with calcium in a crystal matrix known as dolomite (CaCO3 – MgCO3). Dolomite is rather un-reactive and stones containing a significant dolomite content may require excess feed to achieve the required SO2 removal. Limestones typically also contain inert materials, including siliceous compounds such as quartz. These have different densities than the scrubber byproducts and may negatively affect slurry separation device performance. Iron in limestone can form oxides that plug vacuum filter cloths. Iron can also influence gypsum scale formation on scrubber vessel internals, although this is usually not a problem in forced-oxidation systems.

Limestone reactivity is greatly influenced by particle size. A typical method of preparing limestone slurry is to grind the raw limestone with water in a ball mill. This produces a suspended solution of fine limestone particles (slurry), which is then pumped to the reaction vessel. Smaller particle size increases the total surface area of the limestone reactant. Grind size is determined by passing a slurry sample through progressively smaller sieves. A typical specification for grind size in first-generation scrubbers was 70 percent passage through a

200-mesh screen. However, scrubber designers, operators and chemists came to realize that this size was too coarse to promote good utilization. Nowadays, 90 percent or greater passage through a 325-mesh screen is more desirable.

Even with a well-ground, high-purity limestone, utilization may fall short of expected levels. A recent approach is the use of additives to enhance performance. One of the most popular of these is adipic acid (HOOCCH2CH2CH2CH2COOH), which goes by the common name of dibasic acid (DBA). DBA functions by assisting limestone dissolution, which in turn increases sulfur dioxide removal kinetics. Supplemental DBA feed represents a practical approach for enhancing the SO2-removal performance of existing scrubbers.

Improvements have also been made in scrubber vessel construction material. Chlorine in coal converts to hydrogen chloride (HCl) during combustion. HCl is an acid that reacts with limestone to produce calcium and magnesium chloride (CaCl2 and MgCl2), both of which are soluble salts. Chloride concentrations may reach several thousand milligrams per liter. Many first- and second-generation designs incorporated stainless steels in system components. These materials proved unstable when exposed to high chloride concentrations, as chlorides penetrate the protective oxide layer on stainless steels and initiate pitting.

Various inorganic and organic linings have been tested over the years. These often failed due to poor application or simply the stressful nature of the scrubber environment. More exotic materials are not always the answer. Even titanium will fail in the presence of porous slurry deposits, which allow chloride to concentrate at the metal substrate. These conditions are prevalent at the wet-dry interface where flue gas first contacts the slurry sprays. A retrofit technique for some scrubber components, such as scrubber vessel outlet ducts, is overlay (commonly termed wallpapering) of the base metal with a corrosion-resistant material. The most common choices have been the nickel-based alloys C-276 and C-22.

Byproduct Disposal

An issue of continuing importance is byproduct disposal. At plants equipped with forced-air oxidation systems and filter drying systems to produce high grade gypsum, land requirements and costs for byproduct disposal are greatly reduced when plant manufacturers can sell the product to wallboard manufacturers. Other options include gypsum production with landfill of the byproduct, or no forced oxidation with disposal of the byproduct slurry in retention ponds. Some utilities own enough land so that the retention ponds can serve as evaporation ponds, eliminating liquid discharge as an issue. Disposal requirements will undoubtedly become more important due to water conservation issues. Plant personnel are facing regulations that require minimized or zero liquid discharges. No longer can a scrubber be planned without giving thought to liquid discharge issues.

One potential drawback of wet-limestone systems is that they can emit very fine particulates and aerosols. Health and regulatory officials are becoming increasingly concerned about the effects of fine particulates on human well-being. Regulations are becoming increasingly strict with regard to particulate discharge.

Other drawbacks of wet-limestone scrubbing are large up-front capital costs, large equipment size and substantial predictive and corrective maintenance requirements. Substituting hydrated lime as the reagent reduces equipment size and costs, but increases reagent costs and material handling issues. Thus, limestone is more popular as a reagent for wet system handling equipment. This eliminates the need for expensive and maintenance-intensive dewatering and sludge disposal equipment. Also, the drying process does not expose the scrubber materials to chlorides as in wet systems. This relaxes requirements for materials of construction, which in turn lowers capital and building costs.

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Brad Buecker is an air quality control specialist at a large Midwestern power plant. He has previous experience as a chemical cleaning services engineer, a water and wastewater system supervisor and a consulting chemist for an engineering firm. He also served as a results engineer, flue gas desulfurization (FGD) engineer, and analytical chemist for City Water, Light & Power, Springfield, Illinois. Buecker has written more than 70 articles on steam generation, water treatment and FGD chemistry, and is the author of three books on steam generation topics published by PennWell Publishing. He is a member of the ACS, AIChE, ASME, and NACE.

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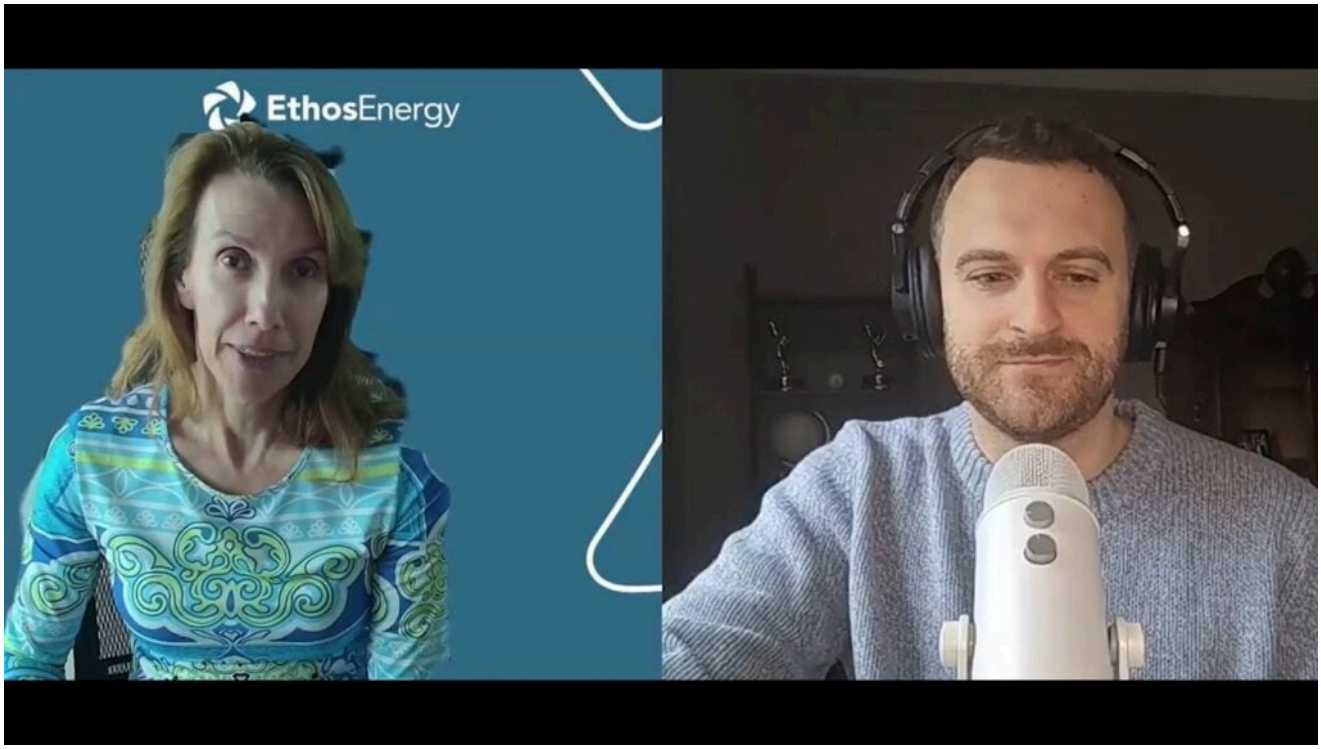
Must View





Inside EthosEnergy’s growth moment with CEO Ana Amicarella

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Sheep grazing gains ground in solar vegetation management

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

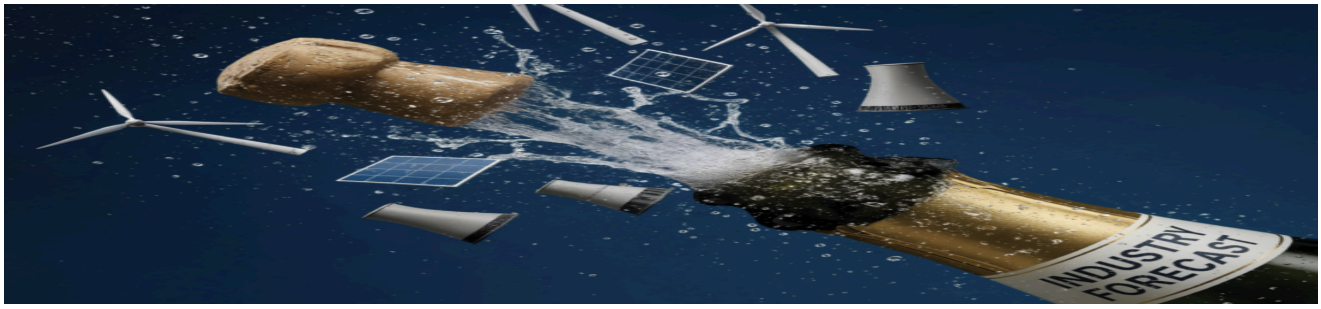
Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-78:
Power Magazine Pulverizers Article

To optimize performance, begin at the pulverizers

www.powermag.com/to-optimize-performance-begin-at-the-pulverizers/

POWER February 15, 2007



Optimizing combustion in pulverized coal (PC)-fired boilers today is more important today than ever. It is well known that the average American PC plant is over 30 years old and that over its lifetime NO_x and SO_2 emissions limits have been steadily ratcheted down (see box). Today, operators no longer wonder whether permissible levels will continue to fall but, rather, when and by how much.

Change is in the air

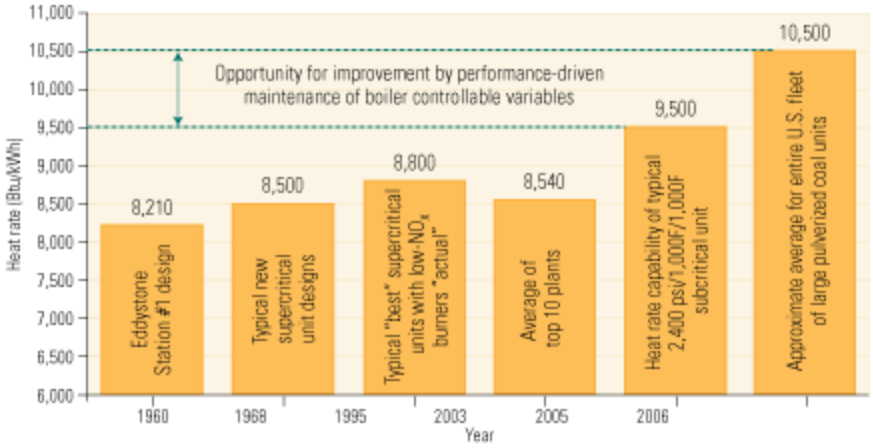
Tighter pollution control has been a common thread in the major evolutionary development of coal-fired generation over the past 30 years:

- Low-NO_x burners, overfire air systems, and other "furnace solutions" have enabled major reductions in NO_x emissions, from 0.5 to 1.5 lb/million Btu to less than 0.15 lb/million Btu.
- Many boilers designed to fire eastern and midwestern bituminous coals have been adapted to burn lower-sulfur Powder River Basin coal at reduced production costs.
- Pulverizers designed for coals with a Hardgrove Grindability Index (HGI) of 50 to 60 are today working with coals that have an HGI in the low 40s.
- Additions of electrostatic precipitator fields and back-end retrofits of baghouses, selective catalytic and noncatalytic reduction systems, and scrubbers have become commonplace.
- Distributed control systems and advanced electronic hardware and software have modernized and optimized boiler operations.
- Public and regulatory pressures are leaning toward mandatory CO_2 emissions caps.

The newest fork in coal-fired generation's path forward is determining how to capture plant emissions of carbon dioxide (CO_2) when—not if—the gas is regulated as a pollutant. Some advocate widespread installations of unproven integrated gasification combined cycle (IGCC) technology ASAP, to prepare it as a long-term solution. Others say building fleets of

super-efficient supercritical and ultrasupercritical-pressure and -temperature plants would be a timelier, more prudent, and more cost-effective alternative. But while regulators, Congress, and the courts wrestle with the question of what to do about greenhouse gases, one thing remains clear: CO_2 emissions could be lowered considerably by raising the efficiency of the existing U.S. fleet of 1,100+ coal plants.

Today's average U.S. PC-fired plant operates at a heat rate of about 10,500 Btu/kWh. Yet a subcritical (2,400 psi/1,000F/1,000F) unit is capable of operating at least 10% more efficiently, at a heat rate of 9,500 Btu/kWh (Figure 1). There are many proven ways to improve a boiler's performance by continuously optimizing its controllable variables (see box). This article explores opportunities for raising a unit's efficiency by improving the performance of its pulverizers.



1. Room for improvement. The heat rate of most older coal-fired steam plants could be lowered by improving their combustion air and fuel systems. Source: Storm Technologies

Storm Technology's experience has demonstrated that, of the 20 key O&M controllable variables with the greatest impact on unit heat rate (see box), most involve the furnace's "burner belt." Essentially (and most often), in a plant operating at its lowest possible heat rate, the combustion airflows, pulverizers, fuel line balancing, burners, and air heaters will all be optimized.

20 boiler variables that can be controlled by O&M practices to improve unit heat rate

1. Flyash loss-on-ignition (LOI), or unburned carbon in ash.

2. Bottom ash carbon content.

3. Boiler and ductwork air in-leakage.

4. Primary airflow. (Measure and control more precisely, to reduced tempering airflows.)

5. Pulverizer air in-leakage on suction-fired mills. (Reduce it.)

6. Pulverizer throat size and geometry. (When optimized, reduces coal rejects and complements operation at lower primary airflows, which reduces tempering airflow and total airflow bypassing the secondary air heater.)

7. Secondary airflow. (When measured and controlled more closely, it enables more precise control of furnace stoichiometry—essential to low-NO_x operation.)

8. Peak upper furnace exhaust gas temperatures. (When too high, they foster "popcorn ash" carryover into the selective catalytic reduction system and air preheater, excessive spray water flows, and boiler slagging and fouling.)

9. Desuperheating spray water flow to the superheater. (Reduce the level.)

10. Desuperheating spray water flow to the reheater. (Reduce the level.)

11. Air heater leakage. (Reduce it; the level for Ljungstrom regenerative air heaters should and can be less than 9%.)

12. Superheater outlet steam temperature.

13. Reheater outlet steam temperature.

14. Air heater exit gas temperature. (Correct it to a "no leakage" basis and optimize it.)

15. Burner "inputs" tuning. (For lowest possible excess oxygen at the boiler outlet and satisfactory NO_x and LOI levels.)

16. Boiler exit (economizer exit) gas temperatures ideally between 650F and 750F, with zero air in-leakage (no dilution).

17. Cycle losses due to valve leak-through. (For spray water valves, reheater drains to the condenser and superheater, reheater drains and vents, and—especially—any low-point drains to the condenser or hotwell.)

18. Sootblowing frequency. (Optimized for maximum cleaning effect and minimal impact on heat rate.)

19. Steam purity. (Turbine deposits negatively impact unit heat rate and capacity.)

20. Auxiliary power consumption. (Minimize it by optimizing fan clearances, duct leakage, fuel and primary air system performance.)

Despite all the changes in regulations, equipment, fuels, and combustion controls over the past few decades, one thing has not changed in evaluating pulverizer performance: You need to get the inputs right! Table 1 breaks down the potential heat rate improvements

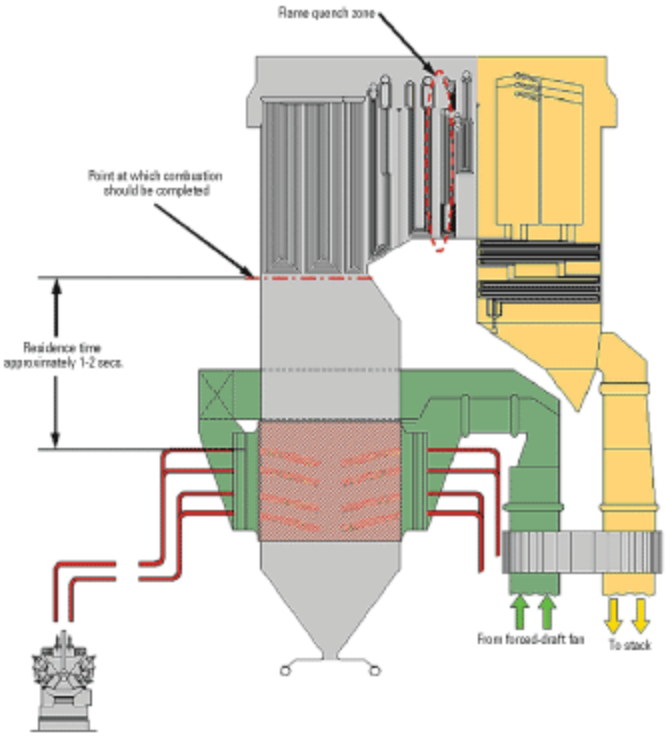
achievable from giving your pulverizer and related systems a good tune-up.

Controllable O&M variable	Heat rate improvement potential (Btu/kWh)
Air in-leakage (reduce)	200
Primary airflow (optimize)	50
Pulverizer performance, fuel line balance (optimize)	100
Air heater leakage (reduce)	80
Coal "pyrites" rejects (reduce)	40
LOI (minimize)	80
Desuperheating spray water flows (minimize)	50
Total	**600**

Table 1. Pulverizer improvements are significant and easy to accomplish. Source: Storm Technologies

Reversal of fortune

Before moving on to some prescriptions for pulverizer optimization, consider the internal configuration of a typical, 1970s-vintage 600-MW PC-fired boiler (Figure 2). The top of the burner belt is about 55 feet below the nose arch, or furnace exit. For optimal production and environmental performance, combustion must be 99% complete by the time its products are passing over the superheater and reheater surfaces. The flue gases are moving swiftly; the residence time in the furnace of the primary air/coal mixture that entered the furnace at the top burner level is less than 2 seconds. Usually, residence time from the top burners to the nose arch is more like 1 second. Remembering the shortness of this interval is important when it is essential to minimize NO_x emissions and when firing fuels with high levels of iron and sodium in their ash.



2. Burned to a crisp. In a typical "thirty-something" pulverized coal-fired boiler, 99+% of combustion should be complete by the time the products of the process reach the convection surfaces. Source: Storm Technologies

Common in-furnace NO_x-reduction solutions include using low-NO_x burners and overfire air (OFA) systems to intentionally stage or slow down combustion. Realizing that delayed combustion is fundamental to the design of all low-NO_x burners and OFA systems helps in understanding why it is so important to optimize pulverizer performance. For example, the ash-softening temperature of a bituminous coal whose ash is high in iron content may be as much as 300 degrees F lower in a reducing (0% oxygen) atmosphere than in an oxidizing environment.

Storm Technologies has found that when coal with high sulfur and high iron content is fired with non-optimized inputs, excessive slagging occurs in the furnace due to the combination of coal chemistry and secondary combustion. The key point to be made here is that the effect of chemistry kicks in when the ash becomes "sticky" or molten, and that happens at a lower temperature with fuel ash high in iron content.

Low-NO_x combustion deliberately consumes some of the furnace residence time for staging combustion and, as a result, contributes to more zones in the upper furnace being in an oxygen-deficient state. Consequently, more slagging occurs and more sootblowing is needed to remove the slag, which reduces heat transfer. Because increased sootblowing increases tube erosion and shortens tube life, suboptimal combustion contributes to reduced plant reliability and availability.

Double down

Suboptimal combustion also takes its toll on unit heat rate:

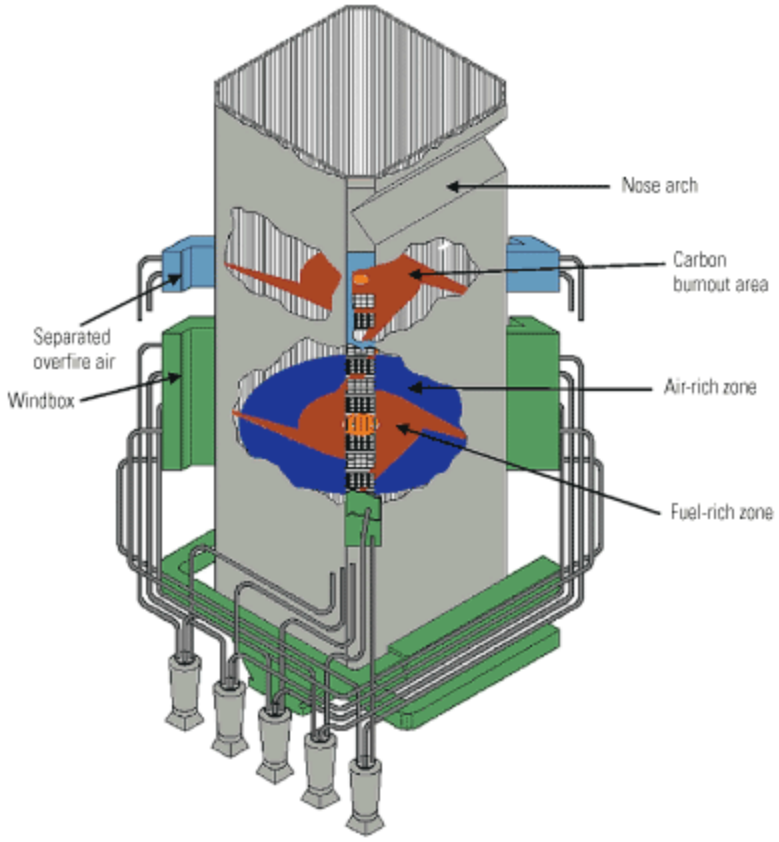
- Each extra sootblowing cycle imposes an overhead cost on steam cycle efficiency.
- The carryover of cinders into the air heater increases draft losses and fan auxiliary power consumption. The increased air heater differential will then increase air in-leakage due to the fouling.
- In units retrofitted with low-NO_x burners or an OFA system, combustion may be actively occurring higher in the furnace, creating secondary combustion. This elevated center of combustion will decrease waterwall heat absorption, elevating the peak furnace exit gas temperature (FEGT). High FEGTs lower combustion efficiency and raise unit heat rate.

Given the extremely short furnace residence times and the staging or slowing of combustion to reduce NO_x formation at the source, it is clear that combustion efficiency must be maximized in the burner belt. Unnecessarily high FEGTs can overheat superheater and reheater metals and cause higher-than-optimal desuperheating spray water flows (imposing a sizable heat rate penalty). Optimizing burner belt performance requires more precise measurement of key boiler performance variables and tighter control of the fuel:air ratio.

Focus on firing

By now, you're probably asking,"What does low–heat rate, low-NO_x boiler performance have to do with pulverizer operation?" Plenty, as it turns out. Several significant factors involved in optimizing combustion with low-NO_x burners are equally applicable to corner-fired and wall-fired boilers.

Let's first consider corner-fired boilers, which are considered inherently forgiving of less-than-optimal combustion tuning. This tolerance seems to derive from the fact that in corner-fired boilers (Figure 3), the entire furnace volume can be considered a single burner into which fuel and air are injected from the corners, creating a burning mass in the center. The burning mass serves to reduce peak temperatures. Meanwhile, tangential injections from the corners impart "swirl" to the fuel and combustion air at all burners; that creates a more homogeneous mix of the products of combustion for fuel-rich and fuel-lean burners. The tangential admission of the fuel and air also slightly increases the residence time of a coal particle, from its introduction into the furnace until its conversion to a burning carbon char particle that is quenched to below 1,400F in the convection pass.

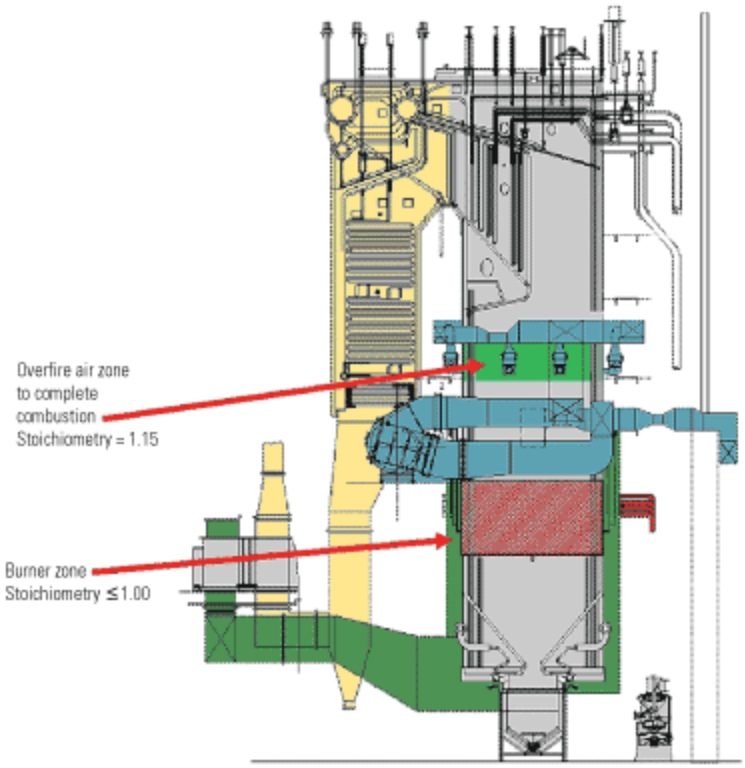


3. Stand in the corner. Corner-fired boilers utilize more of the total furnace for combustion and tend to have lower NO_x emissions. Source: Storm Technologies

The "burning mass" principle also reduces the intensity of combustion in the burner belt, lowering "natural" NO_x levels in the process. Before low-NO_x burner technology was perfected, corner-fired boilers inherently produced less NO_x than wall-fired boilers. Modern, low-NO_x designs stage combustion not only vertically, but horizontally as well.

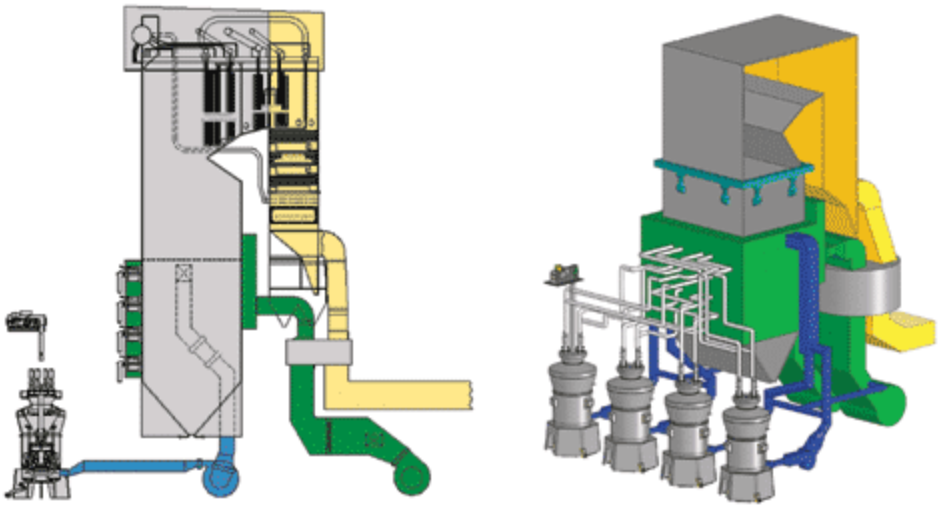
Learn from experience

Another proven way to reduce NO_x emissions without imposing a heat rate penalty is to apply high-momentum OFA through opposed nozzles in the upper furnace. Figure 4 shows the configuration of such a system, as installed both at AES Corp.'s 126-MW Westover Plant in Johnson City, N.Y. (see *POWER*, October 2006) and Savannah Electric's McIntosh Plant.



4. Over and above. NO_x emissions can be reduced by applying high-momentum overfire air through opposed nozzles in the upper furnace. Source: Storm Technologies

In Storm Technologies' experience, wall-fired boilers require fine-tuning of the fuel and air inputs to the burner belt to optimize plant performance, response, and heat rate. A good example is McIntosh Unit 1, a 1975-vintage, 175-MW unit with 16 front wall-mounted burners (Figure 5, left). The furnace division panel separated the eight burners on the right side of the boiler from the eight burners on the left. The 16 burners are arranged in four levels of four across. A fan-boosted OFA system was retrofitted to the unit (Figure 5, right) with excellent results (Table 2). For McIntosh Unit 1, the overall project included optimization of its pulverizers, burners, combustion airflow paths (primary, secondary, and OFA), and improvements to the management and control functions of the systems.



5. You're fired. McIntosh Plant Unit 1 before (L) and after (R) retrofit of a fan-boosted overfire air system. Source: Storm Technologies

Variable	Pre-retrofit	Post-retrofit
Coal fineness (percentage of <HGI coal particles passing 200-mesh screen)	50%–60%	75%–80%
Clean airflow balance (distribution imbalances)	5%–17%	<2%
Fuel flow balance (distribution imbalances)	±20%	±10%
Air-fuel ratio (lb air/lb fuel)	>2.0	~1.8
Flyash loss-on-ignition with Eastern bituminous coals	16%–22%	<10%
Flyash loss-on-ignition with low-rank Venezuelan coals	Not available	<15%
Furnace exit gas temperature (average FEGT/maximum FEGT)	~2,250F/2,400F	<2,200F/2,300F
NO_x (lb/mmBtu)	0.78–1.0	~0.28/0.36 (with 3 or 4 mills operating)

Table 2. Results of retrofitting a fan-boosted overfire air system to Unit 1 of Savannah Electric's McIntosh Plant. Source: Storm Technologies

This wall-fired unit—which has an unforgiving furnace arrangement (furnace division panels and wall-mounted burners) and a relatively short residence time (1 second from the top burners to the nose arch)—validates the potential of using the tenets of combustion optimization found in Table 1. It has test-burned a wide range of coals from South America, Central Appalachia, and the Powder River Basin with good results.

Those results include improved reliability, which must be quantified and factored into the savings equation. Optimized combustion has reduced slagging and fouling. Improved fuel fineness, fuel distribution, and combustion air distribution also have contributed to greater unit availability.

One less well-documented advantage of greater fuel fineness (75% of coal particles pass a 200-mesh screen, and none pass one of 50 mesh) is reduced waterwall wastage. This type of corrosion becomes more severe on boilers operating at supercritical pressure and firing fuels with high sulfur and iron content. Even boilers running at 1,600 to 1,800 psi can have their useful life shortened considerably if their waterwalls are exposed to highly aggressive fireside corrodents of sulfur and iron in a reducing environment.

Future shock

In fact, the industry can expect fireside wastage to become more prevalent as more 30+-year-old plants install SO_2 scrubbers and then are converted to be capable of firing higher-sulfur coals. Why? The reason is because most low-sulfur compliance coals also have low iron content in their ash. These coals are "forgiving" from the perspective of contributing to aggressive fireside corrosion of water walls and slagging. Once a plant owner has spent the money on a scrubber, he will be tempted to buy a higher-sulfur fuel (with higher iron content in its ash) for economic reasons—primarily escalating Western coal rail costs and improved Eastern coal cost-competitiveness. This "reverse fuel switch" trend is likely to foster more slagging, fouling, and aggressive furnace tube corrosion.

Fortunately, there are options available to prevent increases in slagging and fouling that result from a reverse fuel switch. One for minimizing fireside wastage is to optimize pulverizer performance to fuel fineness that’s acceptable in all fuel lines at all times. Storm Technologies’ standard minimum recommended fineness is greater than 75% of particles passing through a 200-mesh screen and none through a 50-mesh screen. Lowering superheater and reheater metal temperatures, to reduce slagging and fouling in the convection passes, is another step than can be taken to improve unit reliability and burner belt combustion.

Finally, operating a unit at its maximum efficiency and capacity should be an overriding economic objective. Optimizing pulverizer performance and burner belt inputs can help reach that goal. So can diagnostic performance testing of fuel lines, combustion airflows, and key upper furnace combustion parameters. When fuel line fineness declines, and reducing environments are found in the furnace, corrective action should be taken immediately.

Cleaner coal-burner

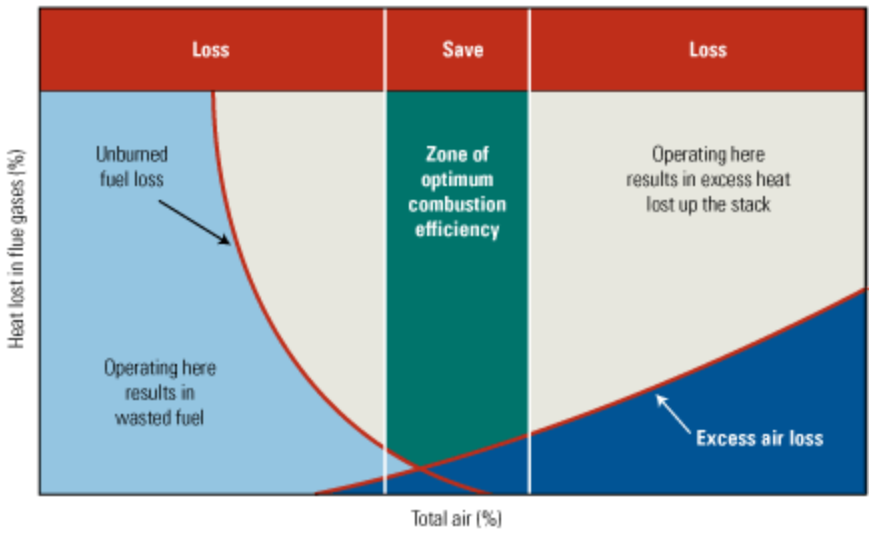
To sum up, there are three significant ways in which optimizing pulverizer performance can contribute to a reduction in a coal-fired boiler’s NO_x emissions.

One. Release of fuel-bound nitrogen in the burner’s devolatilization zone is enhanced by making coal particles smaller, in effect increasing the overall fuel surface area. Low-NO_x burners are most effective when they’re fed coal that has been finely ground. Poor fineness

traps fuel-bound nitrogen within the carbon char particles, beyond the reach of even the best low-NO_x burners.

Two. Fuel balance usually improves with better fuel fineness. A powdery mixture of fine coal particles passing through a pulverizer, classifier, and coal riffles (if the unit is so equipped) will flow more uniformly when it is more finely ground. Such fuels actually flow more like a gas when entrained at the proper ratio in the primary air stream. Fine coal particles mixed in the transport air become more uniformly distributed than coarsely ground coal particles at a similar air/fuel ratio.

Three. A more homogeneous mixture of coal and air entering the burners will naturally reduce required excess air levels. By reducing the total airflow and reducing the excess air, thermal NO_x production is reduced. The better the mixing of the combustion products in the available residence time, the less "extra air" that has to be added to create oxidizing zones in portions of the furnace that are fuel-rich (Figure 6). When these "peaks and valleys" of free oxygen and high temperatures are made more uniform, then it becomes possible to reduce the total excess air that has to be added to make up for imprecise fuel and air inputs into the burner belt.



6. Walk the line. Economic plant operation requires operation in the narrow zone of optimum combustion efficiency. Source: Storm Technologies

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Exhibit 2-79:
Riley Power Low NOx Burner Performance Article

TECHNICAL PUBLICATION

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by:
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Engineer, We Energies

Michael Saari
Sr. Mechanical Engineer, We Energies

K. Scott Trunkett
Market Manager, Conforma Clad Inc.

Bonnie Courtemanche, P.E.
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Presented at:

Electric Power, March 30-April 1, 2004
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&
29th International Technical Conference on Coal Utilization & Fuel Systems, April 19-23, 2004
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ABSTRACT

Electric power generators are experiencing the most complex confluence of market pressures in the history of the industry. Environmental regulations are stricter than ever, forcing producers to make substantial capital investments in emissions conformance, while the pressures of deregulation are making available maintenance dollars ever more scarce. The threat of non-conformance penalties weighs heavily against the pressures of Wall Street, and the decisions between capital expenditures, potential fines, and everyday equipment maintenance becomes a precarious balancing act.

The current high-cost of LNG combined with transmission bottlenecks places low NO_x coal-fired megawatts at a premium, particularly in those regions where generating capacity closely matches demand. This increased value of low NO_x megawatts puts further pressure on personnel to maintain peak performance of their NO_x management systems.

After an electric power generator invests in NO_x reduction technologies to achieve conformance, it is faced with maintaining the equipment to ensure that NO_x rates remain within specified tolerance. Pulverized coal traveling at high velocities through coal burners and burner tips typically produces significant component erosion, causing owners to repeatedly replace parts and even entire burner assemblies. During the period between repairs, changes in burner geometry caused by excessive erosion can impact combustion characteristics, resulting in upward trending NO_x emissions.

The most advanced Low NO_x burner technologies utilize a unique tungsten carbide cladding applied through an infiltration brazing process to protect components against erosion wear, substantially increasing burner life while maintaining combustion characteristics for sustained low NO_x performance. This paper will discuss the exhaustive laboratory analyses used to find the best wear solution for this extreme application, how it is applied, and the performance results of these burners in actual operation after more than two years of service.

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CONFLUENCE OF MARKET PRESSURES IN POWER GENERATION

Power production facilities are under ever-increasing pressure to reduce production costs to compete in a market environment that is more complex today than it's ever been in the past. Failure to effectively reduce production and maintenance costs to a competitive level means reduced profits for each MW-hr sold, and may result in reduced dispatch load—a double jeopardy in a market plagued by over capacity.

The situation is exacerbated by the need for production facilities to balance costs against compliance with a growing number of stringent air quality restrictions for NO_x, SO_x, particulates, and now mercury. These challenges often manifest themselves in a conflicting effort to reduce day-to-day operating costs while optimizing the return on capital investments.

POWER GENERATION AS A BUSINESS

Deregulation and the 1990 Clean Air Act Amendments have often created significant constraints to the operation and maintenance of generation facilities. Before The Clean Air Act Amendments, power producers were relatively unconstrained in the fuels, technologies, and production strategies they employed to meet the market demand. Their primary objective was to provide a reliable source of quality power. Whatever equipment was in place per original design could be used without a great deal of concern for the quality or type of fuel being burned. Original equipment design took into account the planned fuel formulation, and auxiliary equipment was selected primarily based upon these original specifications. Equipment deterioration was accepted as a normal cost of operation, and was dealt with through frequent and relatively long maintenance outages.

Today's competitive market conditions, combined with strict emissions standards, have created entirely new challenges that generate potential conflicts between fuel formulations, equipment configurations, and maintenance programs. Capital expenditures for new advanced Low NO_x burning systems, while designed to support environmental compliance, can lead to unexpected system maintenance challenges, such as rapid component wear. The time deviation between major plant outages for maintenance has increased from one (1) year to as much as four (4) years.

Asset managers are now faced with ever-rising capital investment costs combined with the often-unexpected increase in maintenance costs required to ensure unit availability and acceptable performance. The competitive power generation environment and Wall Street pressures to increase short-term profits further complicate these demands. The combination of these pressures, relatively new to the industry, often drives the use of short-term solution approaches in order to minimize the initial cost of implementation. These factors, all too often, mean that maintenance teams end up chasing ongoing performance and reliability problems with an ever-decreasing staff. While initial capital investment may have been reduced, the ongoing cost of maintaining availability and performance can create a drag on cash flow and reduce the overall return on investment.

RETHINKING INVESTMENTS IN COMPLIANCE

Selection, installation, and implementation of emissions reduction systems frequently involve a large contingent, including plant personnel, corporate engineers and asset teams, numerous contractors and subcontractors, and even subs to the subcontractors. Throughout this complex web of influences, each party has a vested interest in showing the greatest return for the lowest cost. Only a few suppliers, those who have confidence in the value of their innovative and value-added technologies, will be willing to risk losing a project, which might be perceived to be an initially more costly installation. Because of the complexity of the evaluation process, only the savviest of asset owners are able to effec-

tively cut through the smoke and mirrors of promises to recognize the longer term return possible through more advanced, albeit more costly, technologies.

Large power generating assets certainly cost a great deal of money to operate; but they cost even more when, due to degradation of performance and reduced reliability, they are forced into a premature maintenance outage or have to operate at sub-par performance. Higher costs are driven by the incremental replacement power costs. Oftentimes, the payoff for installing lower-cost components is an increased risk of downtime and frequency of maintenance. By thinking about the importance of long-term performance, savvy asset owners are able to parlay smart investments into quantifiable returns. Therefore, it is important to plan capital projects so as to reduce the need for periodic and unnecessary maintenance. The selection of "Best Available Control Technology" will, in many cases, increase initial installation costs only nominally. Savvy asset owners will seek out and explicitly specify such technologies, thus protecting their overall investment against the ill-advised cost-cutting measures employed by many contractors and their subcontractors.

BALANCING ENVIRONMENTAL STEWARDSHIP AGAINST WALL STREET EXPECTATIONS

The war against pollution is mounting, with an ever-increasing list of forbidden effluent constituents, including particulates, SO_2, NO_x, and mercury. NO_x, one of the industry's oldest and most familiar foes, has been challenging boiler designers for the greater part of three decades. Advanced design burner configurations have become one of the industry standard approaches to NO_x abatement, and burner designers are continually developing new ways to achieve and maintain lower levels of NO_x output.

Burner designers are faced with several challenges in the war against NO_x:

- Designing within the parameters of the existing system not originally sized or configured for Low NO_x operation
- Varying coal specifications from the customer which cover wider and wider ranges of fuel properties
- Mill system performance and limitations
- The high heat release rates of some wall-fired cell configurations
- Retrofitting of cell configurations for NO_x reduction without required spacing modifications and pressure part reconfiguration
- Non-homogenous coal flow typically resulting in sub-optimal burner performance
- Coal flow imbalances between pipes requiring additional flexibility of the burner design to compensate for adjusting the airflow to be consistent with coal flow imbalances
- The requirement for burner parts to last up to four (4) years between major outages
- The continuing struggle between decreasing NO_x emissions and maintaining some reasonable level of UBC in the flyash
- The often employed "solution" of highly turbulent mixing resulting in hotter initial burn temperatures and harder to control NO_x

Current state-of-the-industry wall-fired Low NO_x burner designs combine sophisticated mixing and stabilization designs with Best Available Control Technology in wear protection.

Riley Power Inc's (RPI) CCV® burner technology employs a venturi coal nozzle to provide more controllable fuel mixture combined with a low swirl coal spreader to provide good mixing without excessive turbulence. Integral air diverters and stabilizer rings improve flame attachment and reduce NO_x emissions. This combination of sophisticated design component geometries, utilizing an infiltration brazed tungsten carbide protective cladding, ensures that homogenous non-turbulent coal mixing and controlled burn rate is maintained over extended periods of operation. With Best Available Burner Technology, NO_x levels will not only test low at initial startup, but can be expected to remain low throughout the majority of burner life between major outages. This extended performance is achieved by significant reduction in erosion-driven changes in component geometry. The net result is more prolonged compliance with NO_x emissions with reduced risk of both planned and unplanned downtime and an increase in overall unit productivity and reliability.

PERFORMANCE AND LONGEVITY CONSIDERATIONS

The advanced CCV® burner technology has evolved significantly since its initial inception in the early 1980s. Using increasing computing power over the years to perform complex computational fluid dynamic (CFD) analyses and full-scale test facilities, the burner has reached its current advanced state of performance. On a unit firing bituminous fuel with burners only and no overfire air, the NO_x level obtained is 0.36 lb/MMBTU. This can be achieved with a simple "plug-in" retrofit requiring no pressure part replacement, over fired air (OFA), or burner respacing. Burner turndown ratio of 2.5:1 is still maintained. Similar retrofits on units burning sub-bituminous coal achieve NO_x emissions as low as 0.15 lb/MMBTU or less.

In order to protect components against erosion degradation and maintain long-term performance, burner designers performed comprehensive laboratory evaluation of multiple wear protection materials, many of which were industry-accepted, to identify and specify the Best Available Control Technology for the application.

Burner designers tested the following erosion protective materials:

- STOODY 101HC
- SA1750 CR
- Conforma Clad WC219
- Stellite 31
- A560 Grade 50Cr-50Ni
- A532-82 Type II Class C
- A532-82 Type I Class A
- Silicon Carbide
- Stellite 6



Figure 1 - Test Fixture with Sample

Testing utilized an ASTM standard G73 method utilizing Black Beauty Coal Slag as the erodent material (See Figure 1). As a result of this testing, burner designers selected Conforma Clad infiltration brazed WC219 tungsten carbide cladding as the Best Available Control Technology for protecting burner components against erosion deterioration to ensure long-term performance (See Figure 2). Conforma Clad's proprietary cloth application technique makes it highly unique in that it can be easily applied to very complex geometry components, forms a true metallurgical bond with the base component, has an extremely uniform thickness and density, and is not subject to spalling, with the ability to withstand continuous operation at temperatures in excess of 1900 º F. The method of application produces an impervious cladding layer with no interconnected porosity or check cracking, and carbon dilution at the bond line is virtually zero. This, combined with its non-magnetic characteristic, allows for precision in situ measurement of remaining thickness and life-extrapolation in support of predictive maintenance programs.

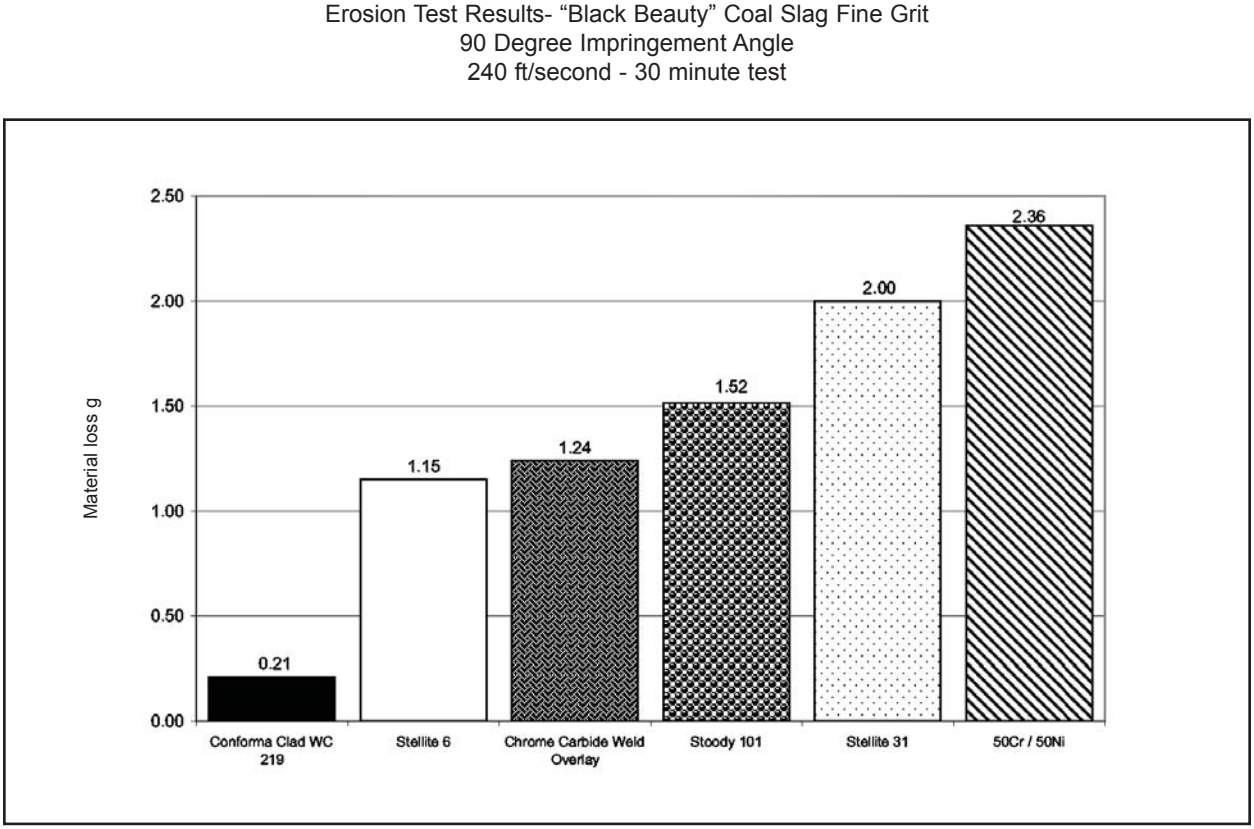

Figure 2 - Erosion Comparison Results

CASE STUDY I

In 1994 RPI retrofitted all four boilers at We Energies, Valley Power Plant, with *first* generation low NO_X burners. The pre-retrofit NO_X levels were 1.02 lb/MMBTU. After the installation of the burners, NO_X levels were reduced to 0.41 lb/MMBTU. An integral component of the RPI design is the low swirl coal spreaders found in the coal nozzle of the burner. The spreader is designed to enhance the combustion by controlling the flame length and minimizing both NO_X and Unburned Carbon (UBC).

New low swirl coal spreaders were installed into the existing CCV® low NO_X burners at We Energies Valley Station, Unit 2, Boiler 3 in February of 2003 as part of the normal maintenance schedule. Several of the materials tested in the laboratory were supplied for a direct comparison. They were installed in burners fed by the same mill. Three (3) low swirl coal spreaders were supplied for installation; one of Riloy 74 clad with Conforma Clad infiltration brazed tungsten carbide, and two of cast silicon carbide.

RPI, working in partnership with We Energies, chose Valley Power Plant as a test site due to the burner velocities and fuel properties, which contribute to high erosion rates. Typical coal/primary airflow velocity through burners at full load is approximately 87 ft/sec. The pulverized coal fired at this station is blended with approximately 9% petroleum coke and the ultimate analysis is shown below:

Carbon:	61.29 - 69.31 %	Sulfur:	0.74 - 0.98 %
Hydrogen:	4.18 - 4.82 %	Ash:	4.19 - 15.37 %
Nitrogen:	1.36 - 1.51 %	Moisture	8.14 - 10.51%
Oxygen:	8.92 - 9.31 %	Hard Grove	46 HGI

Valley Station stopped receiving pet coke April 2003

Due to relatively high nozzle velocity, combined with the high silica and alumina content in the coal, this burner application is considered to be a moderately high erosive environment. This is evident from the wear that can be seen on the burner components that were not protected with tungsten carbide cladding (See Figures 3 and 4).

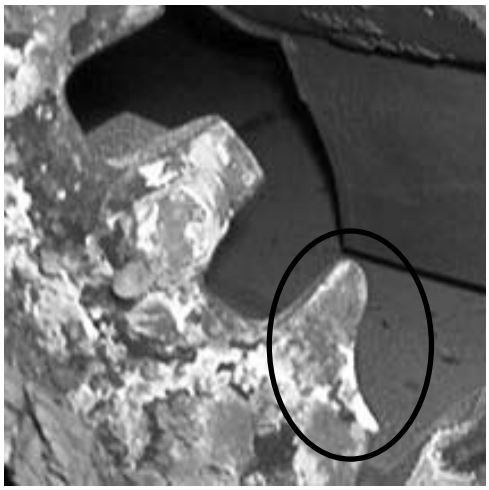

Figure 3 - Unit # 2, Boiler # 3 unprotected burner component showing typical wear after 22 months of service

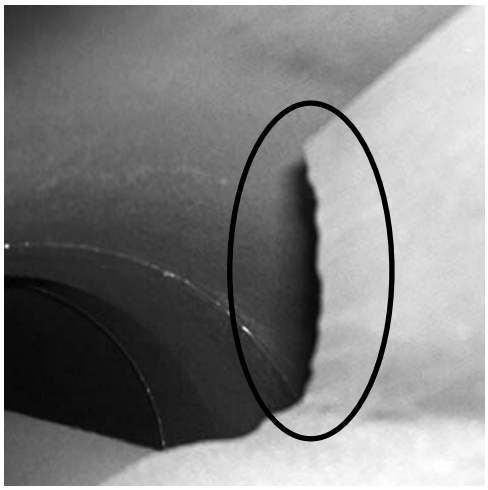

Figure 4 - Stellite Weld Overlay on the leading edge shows approximately 1 1/2" off vane leading edge after nine months of service

As part of development and evaluation of the selected tungsten carbide erosion protection, burner designers chose to install a single component (coal spreader, See Figure 5) protected with the chosen material as a test to confirm performance in operation. This prototype burner test piece was protected with 0.040" thickness of Conforma Clad WC219 applied directly to the leading edge of the spreader base material using a proprietary infiltration brazing process. The prototype coal spreader was installed in Unit 2, Boiler 3, D1 burner location on February of 2003 along with the balance of coal spreaders being supplied with stellite weld overlay on the leading edges. After approximately 9 months of continuous service, the prototype test piece was inspected on October 20, 2003.

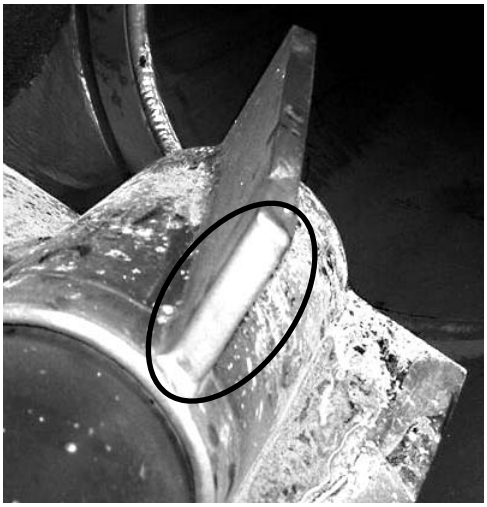

Figure 5 - Conforma Clad infiltration brazed tungsten carbide spreader shows no visable wear

Prior to the installation of the test spreader and new coal spreaders in the remaining burners, recorded NO_X emissions from the CEMS for the third quarter of 2002 show a sustained NO_X performance of 0.423 lb/MMBTU at full load. The NO_X emissions recorded from the CEMS for fourth quarter of 2002 after the equipment component changes showed an average of 0.413 lb/MMBTU at full load.

Results for Case Study I

The stellite protected coal spreader shown in Figure 4 has approximately 1-1/2" of the coal spreader vane missing. The prototype test piece, protected with tungsten carbide cladding was visually inspected and showed no visible signs of erosion (See Figure 5). Due to the non-magnetic nature of the cladding protection, it was possible to measure actual remaining cladding thickness using an Elcometer eddy current thickness gauge. Measurements showed that the maximum extent of erosion was 0.007", or less than 20% of the total protective layer thickness (See Table 1). From these results the predicted life of the coal spreader protected by the tungsten carbide coating is estimated at approximately 5 years.

Table 1
Cladding Thickness Measurements

	BASE	MIDDLE	TIP	
LEADING EDGE				
VANE 1	.042"	.036"	.039"	
VANE 2	.040"	.033"	.043"	
VANE 3	.038"	.036"	.039"	
VANE 4	.039"	.037"	.040"	
BODY	1	2	3	4
LOCATION	.038"	.039"	.037"	.036"

CASE STUDY II

A second installation of Conforma Clad was applied to the new coal flow distributor elements installed at We Energies, Presque Isle Power Plant. In 2001 PIPP installed RPI's low NO_x CCV® second generation Dual Air Zone Burners. In conjunction with this installation, modifications were made to the coal mill system to improve the coal pipe-to-pipe balance to improve the overall unit performance. The coal flow distributor installed by RPI was designed for installation in the coal stream exiting the mill. This location has the potential to experience severe erosion due to sliding and impact abrasion.

Conforma Clad Inc. agreed to test their tungsten carbide material on this application due to the unique location of the device and the wear characteristics of the fuel.

Fuel Composition:		Ash Composition:	
Carbon:	73.8 - 74.2 %	Silicon Dioxide:	56%
Hydrogen:	5.0 - 5.1 %	Aluminum Oxide:	25%
Nitrogen:	1.6 %	Iron Oxide:	5%
Oxygen:	8.8 - 9.1 %	Sulfur Trioxide:	2%
Sulfur:	0.82 - 0.85 %	Calcium Oxide:	4%
Ash:	9.1 - 9.9 %	Other:	8%

Results for Case Study II

The coal flow distributors were installed in Unit #6 pulverizers in December of 2002. The coal flow distributors for Unit #5 were installed in February of 2003. Although the two units have slightly different operating times, a good comparison can be made between the unprotected flow elements in Unit #6, which were inspected in September of 2003, and the Unit #5 elements which were inspected in October of 2003.



Figure 6 - No protective cladding on the flow element

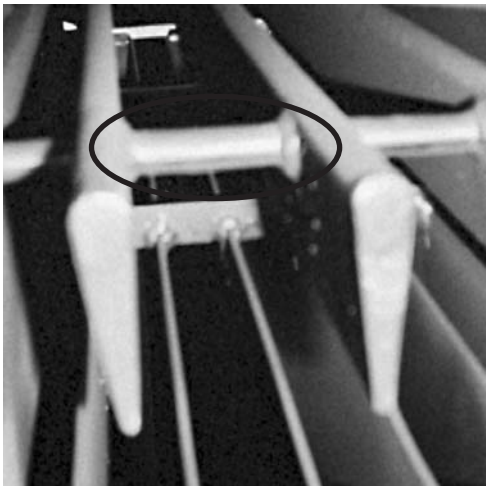

Figure 7 - Leading edge protected with Conforma Clad infiltration brazed tungsten carbide

Figure 6 shows the unprotected element installed in the Unit #6 D pulverizer. These elements are made from a heat-treated alloy with a hardness of 300+ Brinell. Figure 7 shows the same element design clad with tungsten carbide supplied by Conforma Clad.

Initial base cladding thickness was 0.040". With braze scale (Un-melted Chrome), the resulting total cladding thickness was approximately 0.045 - 0.050". From the thickness measurements shown in Table 2, it can be seen that the braze layer, which has a hardness of approximately 57Rc and is relatively erosion resistant, had not yet been penetrated.

Table 2
Cladding Thickness Measurements

	Inboard						Outboard
Location on Vane	1	2	3	4	5	6	7
Left	0.047	0.048	0.049	0.048	0.050	0.048	0.050
Left Center	0.048	0.048	0.047	0.046	0.046	0.046	0.048
Right Center	0.046	0.047	0.046	0.046	0.046	0.047	0.048
Right	0.049	0.051	0.047	0.051	0.049	0.049	0.049

CONCLUSION

Plant maintenance teams are experiencing ever-increasing pressures to reduce the cost of maintaining critical low NO_x burner equipment, and are expected to use innovative methods to maintain emissions compliance while extending the operating period between unit shutdowns. Technologies are available that have proven their ability, in both the laboratory and in the field, to provide substantial protection against some of the most common causes of aggressive equipment wear present in coal-fired power plants, including those present in Low NO_x burner systems.

Innovative burner designers can take advantage of sophisticated protection technologies to extend run time between repairs and component replacement to ensure that their systems provide peak performance not only at startup, but for several years thereafter. Asset managers can realize greater returns on their capital investments with only a nominal increase in initial installation cost through their awareness of proven Best Available Control Technologies.

The data contained herein is solely for your information and is not offered,
or to be construed, as a warranty or contractual responsibility

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-80:
Neundorfer Fabric *Filter Design*

Lesson 5

Fabric Filter Design Review

Goal

To familiarize you with the factors to be considered when reviewing baghouse design plans for air pollution control programs.

Objectives

At the end of this lesson, you will be able to do the following:

1. List and explain at least six factors important in good baghouse design
2. Estimate the cloth area needed for a given gas process flow rate
3. Calculate the number of bags required in a baghouse for a given process flow rate
4. Calculate the gross air-to-cloth ratio, the net air-to-cloth ratio, and the net,net air-to-cloth ratio for a baghouse design

Introduction

The design of an industrial baghouse involves consideration of many factors including space restriction, cleaning method, fabric construction, fiber, air-to-cloth ratio; and many construction details such as inlet location, hopper design, and dust discharge devices. Air pollution control agency personnel who review baghouse design plans should consider these factors during the review process.

A given process might often dictate a specified type of baghouse for particulate emission control. The manufacturer's previous experience with a particular industry is sometimes the key factor. For example, a pulse-jet baghouse with its higher filter rates would take up less space and would be easier to maintain than a shaker or reverse-air baghouse. But if the baghouse was to be used in a high temperature application (500°F or 260°C), a reverse-air cleaning baghouse with woven fiberglass bags might be chosen. This would prevent the need of exhaust gas cooling for the use of Nomex felt bags (on the pulse-jet unit), which are more expensive than fiberglass bags. All design factors must be weighed carefully in choosing the most appropriate baghouse design.

Review of Design Criteria

The first step in reviewing design criteria is determining the flow rate of the gas being filtered by the baghouse, which is measured in cubic meters (cubic feet) per minute. The gas volume

to be treated is set by the process exhaust, but the filtration velocity or air-to-cloth ratio is determined by the baghouse vendor's design. The air-to-cloth ratio that is finally chosen depends on specific design features including fabric type, fibers used for the fabric, bag cleaning mechanism, and the total number of compartments, to mention a few. Figure 5-1 depicts a number of these design features. A thorough review of baghouse design plans should consider the following factors.

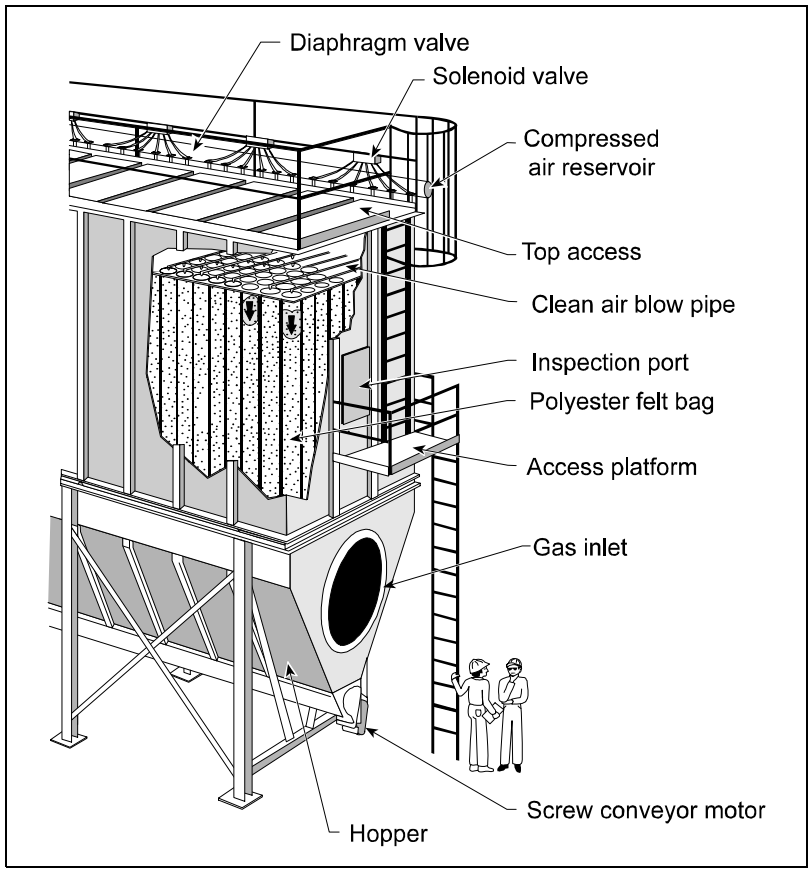

Figure 5-1. Design considerations for a pulse-jet baghouse

Physical and chemical properties of the dust are extremely important for selecting the fabric that will be used. These include size, type, shape, and density of dust; average and maximum concentrations; chemical and physical properties such as abrasiveness, explosiveness, electrostatic charge, and agglomerating tendencies. For example, abrasive dusts will deteriorate fabrics such as cotton or glass very quickly. If the dust has an electrostatic charge, the fabric choice must be compatible to provide maximum particle collection yet still be able to be cleaned without damaging the bags.

Predicting the gas flow rate is essential for good baghouse design. The average and maximum flow rate, temperature, moisture content, chemical properties such as dew point, corrosiveness, and combustibility should be identified prior to the final design. If the baghouse is going to be installed on an existing source, a stack test could be performed by the industrial facility to determine the process gas stream properties. If the baghouse is being installed on a new source, data from a similar plant or operation may be used, but the baghouse should be designed conservatively (large amount of bags, additional compartments, etc.). Sometimes,

heavy dust concentrations are handled by using a baghouse in conjunction with a cyclone pre-cleaner, instead of building a larger baghouse. Once the gas stream properties are known, the designers will be able to determine if the baghouse will require extras such as shell insulation, special bag treatments, or corrosion-proof coatings on structural components.

Fabric construction design features are then chosen. The design engineers must determine the following: woven or felt filters, filter thickness, fiber size, fiber density, filter treatments such as napping, resin and heat setting, and special coatings. Once dust and gas stream properties have been determined, filter choice and special treatment of the filter can be properly made. For example, if the process exhaust from a coal-fired boiler is 400°F (204°C), with a fairly high sulfur oxide concentration, the best choice might be to go with woven glass bags that are coated with silicon graphite or other lubricating material such as Teflon.

Along with choosing the filter type the designer must select the appropriate **fiber type**. Fibers typically used include cotton, nylon, fiberglass, Teflon, Nomex, Ryton, etc. The design should include a fiber choice dictated by any gas stream properties that would limit the life of the bag. (See Lesson 4 for typical fabrics and fibers used for bags.) For more information about fabric construction, see McKenna and Turner (1989).

Proper air-to-cloth (A/C) ratio is the key parameter for proper design. As stated previously, reverse-air fabric filters have the lowest A/C ratios, then shakers, and pulse-jet baghouses have the highest. For more information about air-to-cloth ratios, see McKenna and Turner (1989).

Once the bag material is selected, the **bag cleaning methods** must be properly matched with the chosen bags. The cost of the bag, filter construction, and the normal operating pressure drop across the baghouse help dictate which cleaning method is most appropriate. For example, if felted Nomex bags are chosen for gas stream conditions that are high in temperature and somewhat alkaline (see Table 4-1), pulse-jet cleaning would most likely be used.

The **ratio of filtering time to cleaning time** is the measure of the percent of time the filters are performing. This general, “rule-of-thumb” ratio should be at least 10:1 or greater (McKenna and Furlong 1992). For example, if the bags need shaking for 2 minutes every 15 minutes they are on-line, the baghouse should be enlarged to handle this heavy dust concentration from the process. If bags are cleaned too frequently, their life will be greatly reduced.

Cleaning and filtering stress is very important to minimize bag failures. The amount of flexing and creasing to the fabric must be matched with the cleaning mechanism and the A/C ratio; reverse-air is the gentlest, shaking and pulse-jet place the most vigorous stress on the fabric. For example, it would probably not be advisable to use woven glass bags on a shaker baghouse. These bags would normally not last very long due to the great stress on them during the cleaning cycle. However, fiberglass bags are used on reverse-air baghouses that use shake-and-deflate cleaning. Also, some heavy woven glass bags (16 to 20 oz) are used on pulse-jet units (which also have high cleaning stress).

Bag spacing is very important for good operation and ease of maintenance. Bag spacing affects the velocity at which the flue gas moves through the baghouse compartment. If bags are spaced too close together, the gas velocity would be high because there is very little area between the bags for the gas stream to pass through. Settling of dust particles during bag cleaning would become difficult at high velocities. Therefore, it is preferable to space bags far

enough apart to minimize this potential problem but not so far apart as to increase the size of the baghouse shell and associated costs.

For pulse-jet baghouses, bag spacing is important to prevent bag abrasion. Bag-to-bag abrasion can occur at the bottom of the bags because the bags are attached to the tube sheet only at their tops which allows them to hang freely. Slight bows in the bag support cages or a slight warping in the tube sheet can cause bag-to-bag contact at the bottom of the bags.

Finally, access for bag inspection and replacement is important. For example, in a reverse-air unit, sufficient space between bags should be used so that maintenance personnel can check each bag visually for holes. The bag can either be replaced or a cap can be placed on the tube sheet opening to seal off the bag until it is later changed. The bag layout should allow the bag maintenance technician to reach all the bags from the walkway. One measure of bag accessibility is called bag reach and is the maximum number of rows from the nearest walkway. There is no single value for bag reach, but typical units have a value of 3 or 4.

The **compartment design** should allow for proper cleaning of bags. The design should include an extra compartment to allow for reserve capacity and inspection and maintenance of broken bags. Shaker and reverse-air cleaning baghouses that are used in continuous operation require an extra compartment for cleaning bags while the other compartments are still on-line filtering. Compartmentalized pulse-jet units are frequently being used on municipal solid waste and hazardous waste incinerators for controlling particulate and acid gas emissions.

The design of **baghouse dampers** (also called baghouse valves) is important. Reverse-air baghouses use inlet and outlet dampers for gas filtering and bag cleaning sequences. As described in Lesson 2, during the filtering mode, the compartment's outlet gas damper and inlet dampers are both open. During the cleaning sequence, the outlet damper is closed to block the flow of gas through the compartment. The reverse-air damper is then opened to allow the air for bag cleaning to enter the compartment.

Dampers are occasionally installed in by-pass ducts. By-pass ducts, which allow the gas stream to by-pass the baghouse completely, are a means of preventing significant damage to the bags and/or baghouse. Dampers in by-pass ducts are opened when the pressure drop across the baghouse or the gas temperature becomes too high. However, many state regulatory agencies have outlawed the use of baghouse by-pass ducts and dampers to prevent the release of unabated particulate emissions into the atmosphere.

Space and cost requirements are also considered in the design. Baghouses require a good deal of installation space; initial costs, and operating and maintenance costs can be high. Bag replacement per year can average between 25 and 50% of the original number installed, particularly if the unit is operated continuously and required to meet emission limits less than 0.010 gr/dscf. This can be very expensive if the bags are made of Teflon which are approximately $100 for a 5-inch, 9-foot long bag, or Gore-tex which are approximately $140 for a 6-inch, 12-foot long bag.

The **emission regulations in terms of grain-loading and opacity requirements** will ultimately play an important role in the final design decisions. Baghouses usually have a collection efficiency of greater than 99%. Many emission regulations (and permit limits) require that industrial facilities meet opacity limits of less than 10% for six minutes, thus requiring the baghouse to operate continuously at optimum performance.

Typical Air-To-Cloth Ratios

During a permit review for baghouse installations, the reviewer should check the A/C ratio. Typical A/C ratios for shakers, reverse-air, and pulse-jet baghouses are listed in Table 3-1, Lesson 3.

Baghouses should be operated within a reasonable design A/C ratio range. For example, assume a permit application was submitted indicating the use of a reverse-air cleaning baghouse using woven fiberglass bags for reducing particulate emissions from a small foundry furnace. If the information supplied indicated that the baghouse would operate with an A/C ratio of 6 $(cm^3/sec)/cm^2$ [12 $(ft^3/min)/ft^2$] of fabric material, you should question this information. Reverse-air units should be operated with a much lower A/C ratio, typically 1 $(cm^3/sec)/cm^2$ [2 $(ft^3/min)/ft^2$] or lower. The fabric would probably not be able to withstand the stress from such high filtering rates and could cause premature bag deterioration. Too high an A/C ratio results in excessive pressure drops, reduced collection efficiency, blinding, and rapid wear. In this case a better design might include reducing the A/C ratio within the acceptable range by adding more bags. Another alternative would be to use a pulse-jet baghouse with the original design A/C ratio of 6 $(cm^3/ sec)/cm^2$ [12 $(ft^3/min)/ft^2$] and use felted bags made of Nomex fibers. However, Nomex is not very resistant to acid attack and should not be used where a high concentration of SO_2 or acids are in the exhaust gas. Either alternative would be more acceptable to the original permit submission.

Typical air-to-cloth ratios for baghouses used in industrial processes are listed in Tables 5-1 and 5-2. Use these values as a guide only. Actual design values may need to be reduced if the dust loading is high or the particle size is small. When compartmental baghouses are used, the design A/C ratio must be based upon having enough filter cloth available for filtering while one or two compartments are off-stream for cleaning.

Table 5-1. Typical A/C ratios [$(ft^3/min)/ft^2$] for selected industries[1]

Industry	Fabric filter air-to-cloth ratio		
	Reverse air	Pulse jet	Mechanical shaker
Basic oxygen furnaces	1.5-2	6-8	2.5-3
Brick manufacturing	1.5-2	9-10	2.5-3.2
Castable refractories	1.5-2	8-10	2.5-3
Clay refractories	1.5-2	8-10	2.5-3.2
Coal-fired boilers	1-1.5	3-5	-
Conical incinerators	-	-	-
Cotton ginning	-	-	-
Detergent manufacturing	1.2-1.5	5-6	2-2.5
Electric arc furnaces	1.5-2	6-8	2.5-3
Feed mills	-	10-15	3.5-5
Ferroalloy plants	2	9	2
Glass manufacturing	1.5	-	-
Grey iron foundries	1.5-2	7-8	2.5-3
Iron and steel (sintering)	1.5-2	7-8	2.5-3
Kraft recovery furnaces	-	-	-

Continued on next page

Table 5-1. ***(continued)***
Typical A/C ratios [(ft^3/min)/ft^2] for selected industries[1]

Industry	Fabric filter air-to-cloth ratio		
	Reverse air	Pulse jet	Mechanical shaker
Lime kilns	1.5-2	8-9	2.5-3
Municipal and medical waste incinerators	1-2	2.5-4	-
Petroleum catalytic cracking	-	-	-
Phosphate fertilizer	1.8-2	8-9	3-3.5
Phosphate rock crushing	-	5-10	3-3.5
Polyvinyl chloride production	-	7	-
Portland cement	1.2-1.5	7-10	2-3
Pulp and paper (fluidized bed reactor)	-	-	-
Secondary aluminum smelters	-	6-8	2
Secondary copper smelters	-	6-8	-
Sewage sludge incinerators	-	-	-
Surface coatings spray booth	-	-	-

1. High efficiency: a sufficiently low grain loading to expect a clear stack.
Source: EPA 1976, revised 1992.

Table 5-2. Typical A/C ratios for fabric filters used for control of particulate emissions from industrial boilers.

Size of boiler (10^3 lb steam per hour)	Temperature (°F)	Air-to-cloth ratio [$(ft^3/min)/ft^2$]	Cleaning mechanism	Fabric material
260 (3 boilers)	400°	4.4:1	On- or off-line pulse-jet or reverse-air	Glass with 10% Teflon coating (24 oz/yd^2)
170 (5 boilers)	500°	4.5:1	Reverse-air with pulse-jet assist	Glass with 10% Teflon coating
140 (2 boilers)	360°	2:1	Reverse-air	No. 0004 Fiberglas with silicone-graphite Teflon finish
250	338°	2.3:1	Shake and deflate	Woven Fiberglas with silicone graphite finish
200 (3 boilers)	300°	3.6:1	Shake and deflate	Woven Fiberglas with silicone-graphite finish
400 (2 boilers)	Stoker, 285° to 300°; pulverized coal, 350°	2.5:1	Reverse-air	Glass with Teflon finish
75	150°	2.8:1	Reverse-air	Fiberglas with Teflon coating
50	350°	3:1	On-line pulse-jet	Glass with Teflon finish
270 (2 boilers)	330°	3.7:1	On-line pulse-jet	Teflon felt (23 oz)
450 (4 boilers)	330°	3.7:1	On-line pulse-jet	Teflon felt (23 oz)
380	NA	2:1	Reverse-air vibrator assist	Glass with 10% Teflon coating
645	NA	2:1	Reverse-air vibrator assist	Glass with 10% Teflon coating
1440 (3 boilers)	360°	3.4:1	Shake and deflate	Woven Fiberglas with silicone-graphite finish

Source: EPA 1979.

Simple Cloth Size Check

Baghouse sizing is done by the manufacturer. This example will show you how to verify the manufacture's measurements by doing a simple cloth size check. Given the process gas exhaust rate and the filtration velocity, you can estimate the amount of cloth required by the baghouse. Once you know the total amount of cloth required and the dimensions of a bag, you can calculate the number of bags in the baghouse.

Problem

Calculate the number of bags required for an 8-compartment pulse-jet baghouse with the following process information and bag dimensions.

Q,	process gas exhaust rate	100,000 ft^3/min
A/C,	gross air-to-cloth ratio	4 (ft^3/min)/ft^2
Bag dimensions:		
	bag diameter	6 in.
	bag height	12 ft

Solution

1. **Calculate the total gross cloth area**. Use equation 3-6 (in Lesson 3):

$$v_f = \frac{Q}{A_c} \text{ or } A_c = \frac{Q}{v_f}$$

Where: A_c = cloth area, ft^2
Q = process exhaust rate, ft^3/min
v_f = filtration velocity, ft/min

$$A_c = \frac{100{,}000 \text{ ft}^3 / \text{min}}{4 \text{ ft} / \text{min}}$$
$$= 25{,}000 \text{ ft}^2$$

2. **Determine the amount of fabric required per bag**. Use the formula:

$$A_b = \pi dh$$

Where: A_b = area of bag, ft^2
π = 3.14

Given: d = 0.5 ft, bag diameter
h = 12 ft, bag height

$$A_b = 3.14 \times 0.5 \text{ ft} \times 12 \text{ ft}$$
$$= 18.84 \text{ ft}^2 \text{ required per bag}$$

3. **Calculate the number of bags required in the baghouse**.

$$\text{Number of bags} = \frac{A_c}{A_b}$$

From step 1: $A_c = 25{,}000\ ft^2$

From step 2: $A_b = 18.84\ ft^2$

$$\text{Number of bags} = \frac{25{,}000\ ft^2}{18.84\ ft^2}$$
$$= 1{,}326.96 \text{ bags}$$
$$\text{or } 1{,}328 \text{ bags}$$

So there will be an even number of bags in each of the 8 compartments, round the value 1326.96 up to the next highest multiple of 8 (i.e. 1,328). Thus, there will be 166 bags (1,328/8) in each compartment.

4. **Calculate the net air-to-cloth ratio**. As you recall from Lesson 3, the net air-to-cloth ratio is the A/C ratio when one compartment is taken off-line for bag cleaning or maintenance. Use the formula:

$$(A/C)_{net} = \frac{Q}{A_c\left(\frac{\text{total \# of compartments} - 1}{\text{total \# of compartments}}\right)}$$

Given: $Q = 100{,}000\ ft^3/min$, process exhaust gas rate
The total number of compartments is 8.

From step 1: $A_c = 25{,}000\ ft^2$, total cloth area

$$(A/C)_{net} = \frac{100{,}000\ ft^3/min}{25{,}000\ ft^2(7/8)}$$
$$= 4.57\ (ft^3/min)/ft^2$$

Or, you can simply divide the gross air-to-cloth ratio by 7/8.

$$(A/C)_{net} = \frac{4\ (ft^3/min)/ft^2}{7/8}$$
$$= 4.57\ (ft^3/min)/ft^2$$

5. **Calculate the net, net air-to-cloth ratio** (when two compartments are off-line).

$$(A/C)_{net,\,net} = \frac{(A/C)_{gross}}{\frac{[(\text{total \# of compartments}) - 2]}{\text{total \# of compartments}}}$$

$$(A/C)_{net,\,net} = \frac{4\,(ft^3/min)/ft^2}{6/8}$$

$$= 5.33\,(ft^3/min)/ft^2$$

Review Exercise

1. From the baghouses listed below, which would take up less space because of high filter rates?

   a. Shaker
   b. Pulse-jet
   c. Reverse-air

2. True or False? Gas and dust stream properties influence filter choice.

3. An appropriate “rule of thumb” ratio of filtering time to cleaning time should be at least:

   a. 3:1
   b. 1.5:1
   c. 5:1
   d. 10:1

4. True or False? An air-to-cloth ratio that is too high results in reduced pressure drops.

5. Nomex is not very resistant to:

   a. HCl
   b. CO_2
   c. SO_2
   d. Lead
   e. a and c, only

6. Calculate the area of a bag (A_b) given a bag diameter of 15 inches and a bag height of 20 feet.

   a. 942 ft^2
   b. 70.5 $in.^2$
   c. 78.5 ft^2
   d. 25 ft^2

7. If the cloth area (A_c) is known to be 4,050 ft^2, how many bags would be used in a baghouse with the bag area (A_b) given above?

   a. 52 bags
   b. 519 bags
   c. 120 bags
   d. 10 bags

8. A baghouse has 8 compartments and a gross air-to-cloth ratio of 2.0 $(ft^3/min)/ft^2$. What is the net air-to-cloth ratio?

   a. 1.75 $(ft^3/min)/ft^2$
   b. 2.29 $(ft^3/min)/ft^2$
   c. 2.66 $(ft^3/min)/ft^2$
   d. 16.0 $(ft^3/min)/ft^2$

9. For the baghouse information given in question 8 above, what is the net, net air-to-cloth ratio?

   a. 1.75 $(ft^3/min)/ft^2$
   b. 2.29 $(ft^3/min)/ft^2$
   c. 2.67 $(ft^3/min)/ft^2$
   d. 16.0 $(ft^3/min)/ft^2$

Review Answers

1. **b. Pulse-jet**
   Due to their high filter rates, pulse-jet baghouses take up less space than shaker and reverse-air baghouses.

2. **True**
   Gas and dust stream properties influence filter choice.

3. **d. 10:1**
   An appropriate "rule of thumb" ratio of filtering time to cleaning time should be at least 10:1. If the ratio is much lower, the bags would be cleaned too frequently and may wear out too quickly.

4. **False**
   An air-to-cloth ratio that is too high results in *higher* pressure drops.

5. **e. a and c, only**
   Nomex is not very resistant to HCl and SO_2 (acid gases).

6. **c. 78.5 ft^2**

   Solution:

   1. Calculate the area of a bag (A_b).

$$A_b = \pi dh$$

Given: $\pi = 3.14$
d = 15 in., diameter of bag
h = 20 ft, height of bag

$$A_b = 3.14 \times 15 \text{ in.} \times \frac{1 \text{ ft}}{12 \text{ in.}} \times 20 \text{ ft}$$
$$= 78.5 \text{ ft}^2$$

7. **a. 52 bags**

Solution:

1. Calculate the number of bags.

$$\text{Number of bags} = \frac{A_c}{A_b}$$

Given: $A_c = 4{,}050\ ft^2$, the total cloth area
$A_b = 78.5\ ft^2$, the area of a bag

$$\text{Number of bags} = \frac{4{,}050\ ft^2}{78.5\ ft^2}$$
$$= 52 \text{ bags}$$

8. **b. 2.29 $(ft^3/min)/ft^2$**

Solution:

1. Calculate the net air-to-cloth ratio using the following equation:

$$(A/C)_{net} = \frac{(A/C)_{gross}}{\frac{[(\text{total \# of compartments}) - 1]}{\text{total \# of compartments}}}$$

Given: $(A/C)_{gross} = 2.0\ (ft^3/min)/ft^2$
The total # of compartments is 8.

$$(A/C)_{net} = \frac{2\ (ft^3/min)/ft^2}{7/8}$$
$$= 2.29\ (ft^3/min)/ft^2$$

9. **c. 2.67 (ft^3/min)/ft^2**

Solution:

1. Calculate the net, net air-to-cloth ratio using the following equation:

$$(A/C)_{net,\ net} = \frac{(A/C)_{gross}}{\frac{[(\text{total \# of compartments}) - 2]}{\text{total \# of compartments}}}$$

Given: $(A/C)_{gross} = 2.0\ (ft^3/min)/ft^2$

The total # of compartments is 8.

$$(A/C)_{net,\ net} = \frac{2\ (ft^3/min)/ft^2}{6/8}$$

$$= 2.67\ (ft^3/min)/ft^2$$

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-81:
Norman Kapala 2021 Consumers IRP Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.

Case No. U-21090

Volume 7

PUBLIC RECORD

_____/

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Tuesday, December 7, 2021, at 10:07 a.m.

APPEARANCES:

ROBERT W. BEACH, ESQ.
BRET A. TOTORAITIS, ESQ.
THERESA A.G. STALEY, ESQ.
MICHAEL C. RAMPE, ESQ.
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Jackson, Michigan 49201

On behalf of Consumers Energy Company

(Continued)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
	)	

REVISED DIRECT TESTIMONY

OF

NORMAN J. KAPALA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2021

Q. Please state your name and business address.

A. My name is Norman J. Kapala, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Fossil and Renewable Generation.

Q. What is your formal education experience?

A. In 1996, I received a Bachelor of Science in Mechanical Engineering from Michigan Technological University. In 2008, I received a Master of Science in Manufacturing Management from Kettering University.

Q. Please describe your business experience.

A. From 1990 to 1994, I served our country as a Rifleman in the United States Marine Corps. In May 1996, I joined Chrysler Corporation and held various positions with progressing levels of responsibility at the Trenton Engine Plant, progressing from a Technical Advisor to Area Manager. In September 2002, I joined Delphi Corporation as a Production Supervisor and, in September 2004, progressed to a Senior Manufacturing Engineer. In July 2008, I joined Consumers Energy at the D.E. Karn ("Karn")/ J.C. Weadock ("Weadock") Generating Complex and progressed through positions from Senior Engineer to the Site Business Manager. In June 2015, I transferred to the B.C. Cobb ("Cobb") Generating Complex and J.H. Campbell ("Campbell") Generating Complex as the Site Business Manager for both facilities. Following the closure of seven of the Company's coal-fired units at its Cobb, Weadock, and J.R. Whiting ("Whiting") sites (collectively, the "Classic 7") in 2016, I was promoted to Executive Director of Coal Generation. In April

2020, I was appointed to the position of Executive Director of Fossil and Renewable Generation with operations and maintenance responsibility for Coal, Gas, Wind, and Solar Generation.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

A. Yes. I sponsored testimony in the following MPSC cases:

Case No. U-20165	2018 Integrated Resource Plan under MCL 460.6t;
Case No. U-20202	2018 Power Supply Cost Recovery ("PSCR") Reconciliation;
Case No. U-20219	2019 PSCR Plan;
Case No. U-20220	2019 PSCR Reconciliation;
Case No. U-20525	2020 PSCR Plan;
Case No. U-20844	Ludington Depreciation Case;
Case No. U-20802	2021 PSCR Plan; and
Case No. U-20526	2020 PSCR Reconciliation.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony will address: (i) a description of Consumers Energy's existing generation resources; (ii) the Company's projected capital expenditures and Operations and Maintenance ("O&M") expenses for its existing generation fleet, as those costs were represented in Consumers Energy's Integrated Resource Plan ("IRP") modeling; (iii) the Company's projected capital expenditures and O&M expenses for the Covert combined cycle gas plant ("Covert"), the Dearborn Industrial Generation combined cycle and peaking units ("DIG"), the Kalamazoo River Generating Station peaking plant ("Kalamazoo"), and the Livingston Generating Station peaking plant ("Livingston") that are included in the Company's Proposed Course of Action ("PCA"); (iv) the Company's projected separation

activity costs related to the early retirement of its existing generating units at the Campbell and Karn generating sites; (v) Consumers Energy's avoidable and incremental capital expenditures and expenses in different cases involving the early retirement of Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4; (vi) the performance of the Company's existing generation fleet; (vii) execution risks faced by Consumers Energy if Campbell Units 1, 2, or 1 and 2, Campbell Unit 3, or Karn Units 3 and 4 are selected for early retirement; and (viii) the tax, community, and employee impacts of an early retirement case.

Q. What is the Company's retirement recommendation with respect to Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4?

A. As discussed by several Company witnesses, and as also further explained in my direct testimony, Consumers Energy's PCA proposes to retire Karn Units 3 and 4 in 2023, and retire Campbell Units 1, 2, and 3 in 2025. As discussed in Section II of my testimony, this PCA will result in $75,648,000 in avoided capital expenditures, $15,645,00 in avoided unit separation capital expenditures, and $10,050,000 in avoided major maintenance expenses at Karn Units 3 and 4 compared to the Company's base case outlook ("base case"). In addition, this PCA will result in $~~190,613,000~~136,244,000 in avoided capital expenditures, $64,146,000 in avoided unit separation capital expenditures, and $57,555,000 in avoided major maintenance expenses at Campbell Unit 3; $12,114,000 in avoided capital expenditures and $61,524,000 in avoided major maintenance expenses at Campbell Unit 1; and $13,385,000 in avoided capital expenditures and $84,186,000 in avoided major maintenance expenses at Campbell Unit 2, compared to the Company's base case

assumptions of continued operations to the units current design lives in each of the scenarios described by Company witness Sara T. Walz.

Q. Are there any offsets to the avoided cost numbers?

A. Yes. The avoided capital expenditures, avoided unit separation capital expenditures, and avoided major maintenance expenses would be partially offset by the capital expenditures and O&M expenses for the Covert, DIG, Kalamazoo, and Livingston gas generating plants (collectively "new gas plants") which are discussed in Section III of my direct testimony. The Company is also projecting that it will incur approximately $60,000,000 in employee retention and separation activity expenses, as discussed in Section VIII of my direct testimony; however, the Company does not consider these costs incremental in nature as the Company would have incurred these costs at a later date had an early retirement not occurred.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-50 (NJK-1) Revised	Summary of Capital Expenditures and Operations and Maintenance Expenses;
Exhibit A-51 (NJK-2) Revised	Summary of Projected Generation Operations Capital Expenditures;
Exhibit A-52 (NJK-3)	Summary of Projected Generation Operations Major Maintenance Expenses;
Exhibit A-53 (NJK-4)	Summary of Projected Generation Operations Base O&M Expenses;
Exhibit A-54 (NJK-5)	Generation Operations – Summary of Capital Expenditures and Costs of Removal;

Exhibit A-55 (NJK-6) Revised	Summary of Projected Generation Operations Capital Expenditures and Operations and Maintenance Expenses – new gas plants;
Exhibit A-56 (NJK-7)	Summary of Projected Generation Operations Separation Activity Capital Expenditures;
Exhibit A-57 (NJK-8) Revised	Generation Capital Expenses – Avoidable And Incremental Under an Early Retirement Case 2024 - 2032;
Exhibit A-58 (NJK-9)	Generation Major Maintenance Expenses – Avoidable Under An Early Retirement Case 2024-2032;
Exhibit A-59 (NJK-10)	Generating Unit Random Outage Rates; and
Confidential Exhibit A-60 (NJK-11)	Generating Unit Heat Rates.

Q. Were these exhibits prepared by you or under your direction or supervision?

A. Yes.

SECTION I: EXISTING GENERATION RESOURCES

Q. Please provide an overview of the Company's non-renewable energy generation assets.

A. As of 2020, the Company's total non-renewable owned generation assets had a net demonstrated summer operating capability of 5,292 MW, comprised of the following coal-, oil-, or gas-fired; hydroelectric; and pumped storage facility units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	AGE (years)	RETIREMENT DATE	REMAINING EST. TIME OF OPERATION (years)	LICENSING STATUS	NET GENERATING CAPABILITY (MW)
COAL FIRED							
JH Campbell 1	West Olive, MI	1962	59	2031	10	Active	260
JH Campbell 2	West Olive, MI	1967	54	2031	10	Active	260
JH Campbell 3	West Olive, MI	1980	41	2039	18	Active	785 (owned share)
DE Karn 1	Essexville, MI	1959	62	2023	2	Active	255
DE Karn 2	Essexville, MI	1961	60	2023	2	Active	258
OIL OR GAS FIRED							
DE Karn 3	Essexville, MI	1975	46	2031	10	Active	362
DE Karn 4	Essexville, MI	1977	44	2031	10	Active	362
Zeeland CC	Zeeland, MI	2002	19	2041	20	Active	575
Zeeland 1A	Zeeland, MI	2002	19	2041	20	Active	180
Zeeland 1B	Zeeland, MI	2002	19	2041	20	Active	180
Jackson	Jackson, MI	2002	19	2041	20	Active	547
HYDROELECTRIC							
Alcona	Alcona County, MI	1924	97	n/a	n/a	Active	8
Allegan	Allegan County, MI	1936	85	n/a	n/a	Active	3
Cooke	Iosco County, MI	1911	110	n/a	n/a	Active	9
Croton	Newaygo County, MI	1907	114	n/a	n/a	Active	9
Five Channels	Iosco County, MI	1912	109	n/a	n/a	Active	6
Foote	Iosco County, MI	1918	103	n/a	n/a	Active	9
Hardy	Newaygo County, MI	1931	90	n/a	n/a	Active	30
Hodenpyl	Wexford County, MI	1925	96	n/a	n/a	Active	17
Loud	Iosco County, MI	1913	108	n/a	n/a	Active	4
Mio	Oscoda County, MI	1916	105	n/a	n/a	Active	5
Rogers	Mecosta County, MI	1906	115	n/a	n/a	Active	7
Tippy	Manistee County, MI	1918	103	n/a	n/a	Active	21
Webber	Ionia County, MI	1907	114	n/a	n/a	Active	3
ENERGY STORAGE							
Ludington Units 1-6	Ludington, MI	1973	48	2069	48	Active	1138 (owned share)

Q. What does "owned share" mean when used with respect to Campbell Unit 3?

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 785 MW capacity reported is 93% of the Campbell Unit 3 net demonstrated summer operating capability, reflecting the Company's share of ownership.

Q. What does "owned share" mean when used with respect to Ludington Pumped Storage Plant ("Ludington" or the "Ludington Plant") Units 1-6?

A. The Company owns 51% of the Ludington Plant and DTE Electric Company owns the remaining 49%. Thus, the 1,138 MW capacity reported is 51% of the total Ludington Plant net demonstrated summer operating capability, reflecting the Company's share of ownership.

SECTION II: PROJECTED CAPITAL EXPENDITURES AND O&M EXPENSES OF EXISTING GENERATION FLEET

Q. Please explain Exhibit A-50 (NJK-1) Revised.

A. Exhibit A-50 (NJK-1) Revised shows the projected capital expenditures and major maintenance expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the period of January 1, 2020 through May 31, 2031, and the base O&M expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the same period, under a variety of cases. These are the costs and the date range that the Company used for modeling purposes in this IRP. The Company evaluated a base case, in which all four units (Karn Units 3 and 4 and Campbell Units 1 and 2) retire on May 31, 2031, and then evaluated sixteen early retirement cases related to the Karn and Campbell sites:

- Retirement of Karn Units 3 and 4 on May 31, 2023;
- Retirement of Karn Units 3 and 4 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2032;
- Retirement of Campbell Unit 1 on May 31, 2024;
- Retirement of Campbell Unit 1 on May 31, 2025;

- Retirement of Campbell Unit 1 on May 31, 2026;
- Retirement of Campbell Unit 1 on May 31, 2028;
- Retirement of Campbell Unit 2 on May 31, 2024;
- Retirement of Campbell Unit 2 on May 31, 2025;
- Retirement of Campbell Unit 2 on May 31, 2026;
- Retirement of Campbell Unit 2 on May 31, 2028;
- Retirement of Campbell Units 1 and 2 on May 31, 2024;
- Retirement of Campbell Units 1 and 2 on May 31, 2025;
- Retirement of Campbell Units 1 and 2 on May 31, 2026; and
- Retirement of Campbell Units 1 and 2 on May 31, 2028.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 1 and 2.

A. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, presents the total capital expenditures projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the capital expenditure amounts presented for each unit in each case is a total of all capital expenditures for the period of January 1, 2020 through May 31, 2031. The capital expenditure amounts for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the sixteen early retirement cases, the exhibit presents both the total capital expenditures (including unit separation) over that period that would be made in each respective case and the difference in capital expenditures over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and 3 reflects the early retirement cases for Karn Units 3 and 4; for these cases, the capital expenditures for Karn Units 3 and 4 are reduced versus those shown in the base case. As shown in Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and

3, columns (b) and (c), the 2023 retirement case results in both reduced capital expenditures and also reduced separation costs at Karn Units 3 and 4, and the 2025 retirement case results in reduced capital expenditures at Karn Units 3 and 4, which will be discussed later in my direct testimony. Likewise, Exhibit A-50 (NJK-1) Revised, page 1, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, both the capital expenditures and separation costs for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 1-2, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, lines 6 through 13, columns (c) and (d), shows the reduced or incremental costs for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c) and (d), show reduced costs at Campbell Units 1 and 2 when both units retire. No incremental costs are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Costs of removal are not included in any of the cases in Exhibit A-50 (NJK-1) Revised, page 1, nor are environmental costs related to Steam Electric Effluent Guidelines ("SEEG") and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Heather A. Breining.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 3 and 4.

A. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, presents the total major maintenance expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the major maintenance expenses presented for each unit in each case is a total of all major

maintenance expenses for the period of January 1, 2020 through May 31, 2031. The major maintenance expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total major maintenance expenses over that period that would be made in each respective case, and the difference in major maintenance expenses over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 3, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the major maintenance expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 3, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the major maintenance expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, lines 6 through 13, columns (c) and (d), shows the reduced major maintenance expenses for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17 columns (c) and (d), shows reduced costs at Campbell Units 1 and 2 when both units retire. No incremental major maintenance expenses are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, does not include environmental costs related to SEEG and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 5 and 6.

A. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, presents the total O&M expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the O&M expenses presented for each unit in each case is a total of all O&M expenses for the period of January 1, 2020 through May 31, 2031. The O&M expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total O&M expenses over that period that would be made in each respective case and the difference in O&M expenses over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 5, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the O&M expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 5, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the O&M expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 9, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 1 retirement and increased O&M expenses for Campbell Units 2 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 10 through 13, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 2 retirement and increased O&M expenses for Campbell Units 1 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Units 1 and 2 when both units

retire and increased O&M expenses for Campbell Unit 3. Exhibit A-50 (NJK-1) Revised, pages 5 and 6 do not include environmental costs related to SEEGand Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 1.

A. Exhibit A-51 (NJK-2) Revised, page 1, shows the Company's projected capital expenditures for the Company's generating units at the Campbell and Karn sites for each calendar year over the period from January 1, 2020 through May 31, 2039 in the base case retirement case. In this case, Karn Units 1 and 2 retire on May 31, 2023, Karn Units 3 and 4 and Campbell Units 1 and 2 retire on May 31, 2031, and Campbell Unit 3 retires on May 31, 2039.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1?

A. The capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 2?

A. In 2021, the Company projects to spend:

- $2,859,236 at Karn Units 1 and 2, covering seventeen projects, none of which exceed $500,000;
- $4,172,000 at Karn Units 3 and 4, including:
  - Auxiliary Boiler System Optimization ($2,000,000);
  - Replace House Service Water Screen Drives ($950,000); and
  - Twenty-seven additional projects totaling $1,222,000, with no individual project exceeding $300,000;

- $3,493,440 at Campbell Unit 1, including:
  - Re-align 4160V switchgear with Air Quality Control System ("AQCS") implementation ($1,000,000); and
  - Eleven additional projects totaling $2,493,440, with no individual project exceeding $696,000;
- $13,512,160 at Campbell Unit 2, including:
  - Low Pressure Turbine Overhaul ($3,500,000);
  - Secondary Air Heater Basket and Seal Replacement ($1,750,000);
  - Pulse Jet Fabric Filter ("PJFF") Bag Replacement ($2,394,000); and
  - Seventeen additional projects totaling $5,868,160, with no individual project exceeding $858,100; and
- $19,576,382 at Campbell Unit 3, including:
  - Selective Catalytic Reduction ("SCR") Reactor Catalyst Management ($1,959,510);
  - Replace CO-O2 Monitors ($1,044,600);
  - Mill Complete Overhauls ($1,235,000);
  - Reheater Sootblower ($1,250,000);
  - Sootblowing Air Upgrade ($1,200,000);
  - Replace Lake Michigan Intake Screens ($1,339,000);
  - Cell Construction and Permitting ($5,482,830); and
  - Twenty-two additional projects totaling $6,06,442, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 3?

A. In 2022, the Company projects to spend

- $2,135,136 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $350,000;

- $15,416,000 at Karn Units 3 and 4, including:
  - Tank Farm Storage Tank Heating Lines ($1,400,000);
  - Karn Sync Wire Replacement ($1,320,000);
  - Auxiliary Boiler System Optimization ($1,160,000);
  - Parking Lot Replacement ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($3,000,000);
  - Karn 3 Cooling Tower Rebuild ($2,500,000); and
  - Twenty-two additional projects totaling $5,036,000, with no individual project exceeding $450,000;
- $7,300,000 at Campbell Unit 1, including:
  - PJFF Bag Replacement ($1,578,000);
  - Superheat Outlet Pendant – partial replacement ($3,490,000); and
  - Five additional projects totaling $2,232,000, with no individual project exceeding $750,000;
- $5,256,500 at Campbell Unit 2, including:
  - Catalyst Management ($1,120,000);
  - Replace Burner Assemblies ($1,350,000); and
  - Six additional projects totaling $2,786,500, with no individual project exceeding $836,500; and
- $17,125,333 at Campbell Unit 3, including:
  - PJFF Bag & Cleaning Air Manifold Replacement ($3,994,601);
  - SCR Reactor Catalyst Management ($1,866,200);
  - Complete Mill Overhauls ($1,264,800);
  - Replace CO-O2 Monitors ($967,400);
  - Design and Install New Large Particle Ash Screen ($1,485,100);
  - Fuel Handling & Infrastructure Repairs ($1,500,000); and

- Sixteen additional projects totaling $6,047,032, with no individual project exceeding $889,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 4?

A. In 2023, the Company projects to spend:

- $1,123,678 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $235,136;
- $10,072,000 at Karn Units 3 and 4, including:
  - Distributed Control System Evergreen Project ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($1,000,000);
  - Karn 3 Cooling Tower Rebuild ($4,800,000);
  - Capital Equipment Repairs ($1,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $7,214,680 at Campbell Unit 1, including:
  - PJFF Filter Bag Replacement ($1,514,100);
  - Replace Air Preheater Baskets and Seals ($1,113,400);
  - Distributed Control System and Simulator Upgrade ($1,500,000);
  - Ashpit Rebuild ($1,000,000); and
  - Twelve additional projects totaling $2,087,180, with no individual project exceeding $750,000;
- $9,472,020 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($5,053,000);
  - SCR Reactor Catalyst Replacement ($2,000,000); and
  - Nine additional projects totaling $2,419,020, with no individual project exceeding $750,000; and
- $~~20,766,757~~20,478,187 at Campbell Unit 3, including:

- PJFF Bag & Cleaning Air Manifold Replacement ($3,263,331);
- Complete Mill Overhauls ($1,295,300);
- Design and Install New Large Particle Ash Screen ($1,008,700);
- Secondary Air Heater basket & seal replacement ($2,425,000)
- High Pressure Feedwater Heater 8A replacement ($5,039,800);
- Fuel Handling & Infrastructure Repairs ($1,500,000); and
- ~~Eighteen~~ Seventeen additional projects totaling $~~7,242,827~~6,954,257, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 5?

A. In 2024, the Company projects to spend:

- $9,775,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($800,000);
  - Karn 3 Cooling Tower Rebuild ($4,950,000);
  - Capital Equipment Repairs ($3,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $9,753,000 at Campbell Unit 1 including:
  - Replace Burners Corner 1-8 ($2,700,000);
  - Replace Air Preheater Baskets and Seals ($1,137,100);
  - Boiler Component Replacement ($3,000,000);
  - Balance of Plant Equipment Replacement ($1,500,000) and
  - Six additional projects totaling $1,415,900, with no individual project exceeding $815,900;
- $11,252,000 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($7,952,000);

- Distributed Control System and Simulator Upgrade ($1,500,000); and
- Four additional projects totaling $1,800,000, with no individual project exceeding $750,000; and

- $~~35,780,799~~33,395,569 at Campbell Unit 3, including:
  - SCR Reactor Catalyst Management ($1,959,510);
  - Turbine Drain Modifications ($2,535,000);
  - Superheat Terminal Drain Replacement ($3,023,100);
  - Replace Boiler Sidewall Panels ($2,425,000);
  - Replace Boiler Front And Rear Wall Panels ($2,482,900);
  - Secondary Air Heater basket & seal replacement ($1,562,000);
  - Fuel Handling & Infrastructure Repairs ($1,500,000);
  - ~~Dry Ash Landfill Closure ($1,635,230);~~
  - Cell Construction and Permitting ($5,482,830); and
  - ~~Twenty-two~~Twenty-one additional projects totaling $~~10,600,029~~12,425,229, with no individual project exceeding $933,100.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 6?

A. In 2025, the Company projects to spend:

- $10,134,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($2,500,000);
  - Karn 3 Cooling Tower Rebuild ($2,565,000);
  - Capital Replacements ($4,000,000); and
  - Three additional projects totaling $1,069,000, with no individual project exceeding $750,000;
- $2,550,000 at Campbell Unit 1, including four projects that do not exceed $669,000 individually; and

- $7,800,000 at Campbell Unit 2, including:
  - Replace turbine right side Reheat Stop Valve body ($1,850,000); and
  - Boiler Component Replacement ($3,000,000);
- Five additional projects totaling $2,950,000, with no individual project exceeding $750,000; and
- $~~30,179,045~~14,512,045 at Campbell Unit 3, including:
  - GSU Replacement ($6,485,045);
  - SCR Reactor Catalyst Management ($3,000,000);
  - AQCS Equipment repair/replacement ($1,000,000);
  - ~~Part 115 JH Campbell B-K landfill cap ($15,667,000)~~
  - Cell Construction and Permitting ($2,000,000); and
  - Four additional projects totaling $2,027,000, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 7?

A. In 2026, the Company projects to spend:

- $9,900,000 at Karn Units 3 and 4, including:
  - Karn 3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($4,000,000);
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($3,000,000);
  - Capital Replacements ($2,000,000); and
  - Three additional projects totaling $6,050,000, with no individual project exceeding $250,000;
- $3,300,000 at Campbell Unit 1, including five projects that do not exceed $750,000 individually;
- $4,420,000 at Campbell Unit 2, including:

- Catalyst Management ($1,120,000); and
- Five additional projects totaling $3,300,000, with no individual project exceeding $750,000; and

- $~~29,053,000~~4,400,000 at Campbell Unit 3, including:
  - ~~Replace Air and Flue Gas Expansion Joints ($2,000,000);~~
  - ~~Part 115 JH Campbell B-K landfill cap ($24,653,000);~~ and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, lines 8 through 20?

A. In each year from 2027 through 2039 in the base case, the Company projects to incur capital expenditures at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, as shown in Exhibit A-51 (NJK-2) Revised, page 1. The capital projects for Karn Units 3 and 4 are as follows:

- 2027: Four projects totaling $8,950,000, which includes:
  - K3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($2,600,000);
  - Karn 3 Distributed Control System ("DCS") & Simulator Evergreen ($1,000,000);
  - Karn 4 DCS & Simulator Evergreen ($1,350,000); and
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($4,000,000);
- 2028-2029: One project each year totaling $2,000,000, for capital replacements;
- 2030: One project totaling $1,000,000, for capital replacements; and
- 2031: One project totaling $500,000, for capital replacements.

The capital projects for Campbell Unit 1 are as follows:

- 2027: Five projects totaling $4,050,000, which include:

- DCS and Simulator Upgrade ($1,500,000); and
- Four additional projects totaling $2,550,000, with no individual project exceeding $750,000;

- 2028: Four projects totaling $3,500,000, which include:
  - Fuel Handling and Infrastructure Replacements ($1,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and
  - Two additional projects totaling $1,500,000, with no individual project exceeding $750,000;
- 2029: Five projects totaling $3,878,000, which includes:
  - PJFF Filter Bag Replacement ($1,578,000);
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,300,000, with no individual project exceeding $500,000;
- 2030: Five projects totaling $2,563,000, which include:
  - PJFF Filter Bag Replacement ($1,513,600); and
  - Four additional projects totaling $1,050,000, with no individual project exceeding $300,000; and
- 2031: One Project totaling $250,000.

The capital projects for Campbell Unit 2 are as follows:

- 2027: Eight projects totaling $6,845,000, which include:
  - Catalyst Management ($2,806,000);
  - PJFF bag replacement ($1,389,000); and
  - Six projects totaling $2,650,000 with no individual project which exceeds $750,000;
- 2028: Six projects totaling $7,394,000, which include;
  - DCS and Simulator Upgrade ($1,500,000);
  - PJFF bag replacement ($1,389,000);

- Fuel Handling and Infrastructure Replacements ($1,000,000);
- AQCS Equipment repair/replacement ($1,000,000); and
- Two projects totaling $1,500,000 with no individual project which exceeds $500,000;

- 2029: Five projects totaling $2,500,000, which include;
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Four projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four projects totaling $1,050,000, with no individual project which exceeds $300,000; and
- 2031: One project totaling $250,000.

The capital projects for Campbell Unit 3 are as follows:

- 2027: ~~Six~~ Five projects totaling $~~30,563,600~~5,900,000, including:
  - ~~Cell~~ Construction and Permitting ($3,500,000);
  - ~~Part 115 JH Campbell B-K landfill cap ($24,663,000);~~ and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2028: Five projects totaling $4,400,000, including:
  - SCR Reactor Catalyst Management ($2,000,000); and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2029: Six projects totaling $11,750,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000);
  - Boiler Component Replacement ($5,000,000);
  - AQCS Equipment repair/replacement ($2,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;

- 2030: ~~Four~~ Five projects totaling $~~4,650,000~~11,150,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000);
  - Cell Construction and Permitting ($6,500,000);
  - AQCS Equipment repair/replacement ($3,000,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2031: Four projects totaling $2,400,000, with no individual project which exceeds $750,000;
- 2032: Four projects totaling $2,750,000, which include:
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2033: Seven projects totaling $11,750,000, which include:
  - SCR Reactor Catalyst Management ($2,000,000);
  - Replace Air and Flue Gas Expansion Joints ($2,000,000);
  - Boiler Component Replacement ($5,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2034: Five projects totaling $5,400,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000); and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2035: Five~~our~~ projects totaling $~~3,650,000~~10,150,000, which include:
  - AQCS Equipment repair/replacement ($2,000,000);
  - Cell Construction and Permitting ($6,500,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;

- 2036: Four projects totaling $4,650,000, which include:
  - AQCS Equipment repair/replacement ($3,000,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2037: Four projects totaling $2,400,000, with no individual project which exceeds $750,000; and
- 2038: Two projects totaling $550,600, with no individual project which exceeds $300,000.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 2.

A. Exhibit A-51 (NJK-2) Revised, page 2, shows the Company's projected capital expenditures for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. As shown in Exhibit A-51 (NJK-2) Revised, page 2, column (c), there are no projected incremental capital expenditures for Karn Units 1 and 2 in these cases, which are discussed later in my direct testimony. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 2, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (d), shows that the Company would avoid $75,648,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (i), shows that the Company would avoid $62,987,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 2, line 13, columns (e) and (j), shows that the Company would avoid $15,465,000 in unit separation capital expenditures and $9,161,000 in unit separation

capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023 and May 31, 2025 respectively.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 3.

A. Exhibit A-51 (NJK-2) Revised, page 3, shows the Company's projected capital expenditures for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025 or on May 31, 2032. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-51 (NJK-2) Revised, page 3, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (c) and (d), show that the Company would avoid $190,613,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (g) and (h), shows that the Company would avoid $31,400,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-51 (NJK-2) Revised, page 3, because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2 retire in a similar timeframe and, therefore, have identical costs to those in the base case through 2026 and 2032.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 4.

A. Exhibit A-51 (NJK-2) Revised, page 4, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 4, also shows the difference in capital expenditures

for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 4, line 13, columns (d) and (e), shows that the Company would avoid $42,840,000 in capital expenditures if Campbell Unit 1 is retired on May 31, 2024 and Campbell Unit 2 would incur incremental capital expenditures of $253,000. Exhibit A-51 (NJK-2) Revised, page 4, line 13, columns (i) and (j), show that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 4, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 5.

A. Exhibit A-51 (NJK-2) Revised, page 5, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 5, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 5,

line 13, columns (d) and (e), shows that the Company would avoid $56,070,000 in capital expenditures if Campbell Unit 2 is retired on May 31, 2024, and Campbell Unit 1 would incur incremental capital expenditures of $322,000. Exhibit A-51 (NJK-2) Revised, page 5, line 13, columns (i) and (j), shows that the Company would avoid $46,573,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid $45,273,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid $18,333,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 6.

A. Exhibit A-51 (NJK-2) Revised, page 6, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 6, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (d) and (e), shows that the Company would avoid

$42,840,000 in capital expenditures at Campbell Unit 1 and $56,070,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2024. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (i) and (j), shows that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and $46,573,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 6, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and $45,273,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 6, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and $18,333,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures because the unit separation capital expenditures reflected in the base case are not avoided.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1?

A. The major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 2?

A. In 2021, the Company projects to spend:

- $3,771,000 at Karn Units 1 and 2, covering 21 projects, none of which exceeds $700,000;

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $11,930,200 at Campbell Units 1 and 2 including:
  - Campbell 2 Generator Overhaul-Rewedge-Collector Ring Replacement ($3,630,000);
  - Campbell 2 Turbine Inspection and Overhaul ($2,370,000);
  - Campbell 1 and 2 Periodic Outage Maintenance ($1,512,000); and
  - Twenty-two additional projects totaling $4,418,200, with no individual project exceeding $750,000; and
- $5,102,729 at Campbell Unit 3 including:
  - Campbell 3 Turbine Valve Inspection ($1,200,000); and
  - Twenty-two additional projects totaling $3,902,729, with no individual project exceeding $715,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 3?

A. In 2022, the Company projects to spend:

- $3,292,000 at Karn Units 1 and 2, covering 19 projects, none of which exceeds $700,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,537,000 at Campbell Units 1 and 2 including:
  - Campbell 1 and 2 Periodic Outage Maintenance ($1,248,000); and
  - Thirteen additional projects totaling $2,289,000, with no individual project exceeding $600,000; and
- $4,208,040 at Campbell Unit 3 including:
  - Boiler Feed Pump Turbine Inspection ($1,680,000); and
  - Fourteen additional projects totaling $2,528,040, with no individual project exceeding $425,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 4?

A. In 2023, the Company projects to spend:

- $826,000 at Karn Units 1 and 2, covering seven projects, none of which exceeds $200,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $2,905,000 at Campbell Units 1 and 2 covering 10 projects, none of which exceeds $643,667; and
- $2,523,970 at Campbell Unit 3 covering 12 projects, none of which exceeds $425,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 5?

A. In 2024, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $3,405,167 at Campbell Units 1 and 2 covering 12 projects, none of which exceeds $655,167; and
- $12,954,250 at Campbell Unit 3 including:
  - Campbell 3 Turbine Overhaul ($7,931,350);
  - Campbell 3 Boiler Chemical Cleaning ($1,429,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,000,000);
  - Campbell 3 Periodic Outage Maintenance ($933,100); and
  - Eight additional projects totaling $1,660,800, with no individual project exceeding $430,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 6?

A. In 2025, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $4,569,000 at Campbell Units 1 and 2 including:
  - Campbell 2 Turbine Valve Inspection ($1,300,000); and
  - Seven additional projects totaling $3,269,000, with no individual project exceeding $666,667; and
- $3,810,600 at Campbell Unit 3 including:
  - Campbell 3 Turbine Valve Inspection ($1,200,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six additional projects totaling $1,410,600, with no individual project exceeding $450,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 7?

A. In 2026, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,541,000 at Campbell Units 1 and 2 covering nine projects, none of which exceed 678,167; and
- $1,660,600 at Campbell Unit 3 covering five projects, none of which exceed 500,000.

Q. What is the basis for the projected expenses in Exhibit A-52 (NJK-3), page 1, lines 8 through 20?

A. In each year from 2027 through 2039 in the base case, the Company projects to incur major maintenance expenses at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3,

as shown in Exhibit A-52 (NJK-3), page 1. The number of individual major maintenance projects for Karn Units 3 and 4 is as follows:

- 2027: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2028: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2029: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2030: Seven projects totaling $800,000, with no individual project which exceeds $250,000; and
- 2031: Three projects totaling $250,000, with no individual project which exceeds $150,000.

The number of individual major maintenance projects for Campbell Unit 1 is as follows:

- 2027: Seven projects totaling $2,129,667, with no individual project which exceeds $689,667;
- 2028: Six Projects totaling $2,351,167, with no individual project which exceeds $750,000;
- 2029: Six Projects totaling $1,952,667, with no individual project which exceeds $712,667;
- 2030: Four Projects totaling $1,300,000, with no individual project which exceeds $500,000; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 2 is as follows:

- 2027: Seven projects totaling $1,423,333, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,533,833, with no individual project which exceeds $500,000;

- 2029: Six Projects totaling $3,294,333, which includes;
  - Campbell 2 Turbine Valve Inspection ($1,400,000); and
  - Five Projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four Projects totaling $1,204,833, with no individual project which exceeds $404,833; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 3 is as follows:

- 2027: Nine projects totaling $2,560,600, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,830,600, with no individual project which exceeds $500,000;
- 2029: Eight Projects totaling $3,860,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,300,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2030: Six Projects totaling $1,910,600, with no individual project which exceeds $500,000;
- 2031: Seven Projects totaling $1,960,600, with no individual project which exceeds $500,000;
- 2032: Seven Projects totaling $15,330,600, which includes:
  - Campbell 3 Turbine Overhaul ($12,000,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($2,000,000); and
  - Five Projects totaling $1,330,600 with no individual project which exceeds $500,000;
- 2033: Eight Projects totaling $3,860,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,300,000);

- Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
- Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;

- 2034: Five Projects totaling $1,710,600, with no individual project which exceeds $500,000;
- 2035: Eight Projects totaling $2,260,600, with no individual project which exceeds $500,000;
- 2036: Six Projects totaling $1,850,600, with no individual project which exceeds $500,000;
- 2037: Eight Projects totaling $3,960,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,400,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2038: Five Projects totaling $1,360,600, with no individual project which exceeds $500,000; and
- 2039: Three Projects totaling $310,600, with no individual project which exceeds $110,600.

Q. Please explain Exhibit A-52 (NJK-3), page 2.

A. Exhibit A-52 (NJK-3), page 2, shows the Company's projected major maintenance expenses for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 2, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 2, line 13, column (c), shows that the Company would avoid $10,050,000 in major maintenance expenses if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-52 (NJK-3), page 2, line 13, column (f), shows

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Generation Operations - Capital - Base Retirement Case

Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039

Line No.	Year	(a) Karn 1/2 Total	(b) Karn 3/4 Total	(c) Campbell 1 Total	(d) Campbell 2 Total	(e) Campbell 3 Total
1	2020	7,176	8,679	10,025	9,268	12,860
2	2021	2,859	4,172	3,493	13,512	19,576
3	2022	2,135	15,416	7,300	5,257	17,125
4	2023	1,124	10,072	7,215	9,472	20,478
5	2024		9,775	9,753	11,252	33,396
6	2025		10,134	2,550	7,800	14,512
7	2026		9,900	3,300	4,420	4,400
8	2027		8,950	4,050	6,845	5,900
9	2028		2,000	3,500	7,394	4,400
10	2029		2,000	3,879	2,500	11,750
11	2030		1,000	2,564	1,050	11,150
12	2031		500	250	250	2,400
13	2032					2,750
14	2033					11,750
15	2034					5,400
16	2035					10,150
17	2036					4,650
18	2037					2,400
19	2038					550
20	2039					
21	Total	$ 13,294	$ 82,598	$ 57,878	$ 79,020	$ 195,597

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Capital - Karn 3&4 Early Retirement Case

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Retire Karn 3&4 5/31/2023					**Retire Karn 3 & 4 5/31/2025**			
Line No.	Year	Karn 3&4 Total	Karn 1&2 ariance to Base Cas	Karn 3&4 Variance to Base Case	Karn 3 & 4 Separation Variance to Base Case	Year	Karn 3&4 Total	Karn 1&2 ariance to Base Cas	Karn 3&4 Variance to Base Case	Karn 3 & 4 Separation Variance to Base Case
1	2020	5,500	-	(3,179)	-	2020	8,679	-	-	-
2	2021	750	-	(3,422)	-	2021	6,012	-	1,840	(667)
3	2022	500	-	(14,916)	(13,675)	2022	2,370	-	(13,046)	(7,204)
4	2023	200	-	(9,872)	(1,790)	2023	1,850	-	(8,222)	(1,290)
5	2024	-	-	(9,775)	-	2024	500	-	(9,275)	-
6	2025	-	-	(10,134)	-	2025	200	-	(9,934)	-
7	2026	-	-	(9,900)	-	2026	-	-	(9,900)	-
8	2027	-	-	(8,950)	-	2027	-	-	(8,950)	-
9	2028	-	-	(2,000)	-	2028	-	-	(2,000)	-
10	2029	-	-	(2,000)	-	2029	-	-	(2,000)	-
11	2030	-	-	(1,000)	-	2030	-	-	(1,000)	-
12	2031	-	-	(500)	-	2031	-	-	(500)	-
13	Total	$ 6,950	$ -	$ (75,648)	$ (15,465)	Total	$ 19,611	$ -	$ (62,987)	$ (9,161)

Note:
1. Cost of removal has not been included.

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Generation Operations - Capital - Campbell 3 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Retire Campbell 3 5/31/2025				**Retire Campbell 3 5/31/2032**		
Line No.	Year	Campbell 3 Total	Campbell 3 Variance to Base Cas	Campbell Unit 3 Separation Variance to Base Case	Year	Campbell 3 Total	Campbell 3 Variance to Base Cas	Campbell Unit 3 Separation Variance to Base Case
1	2020	12,860	0	-	2020	12,860	0	-
2	2021	18,397	(1,179)	-	2021	19,576	-	-
3	2022	12,885	(4,240)	-	2022	17,125	-	-
4	2023	8,705	(11,773)	-	2023	20,478	-	-
5	2024	6,044	(27,352)	-	2024	33,396	-	-
6	2025	400	(14,112)	-	2025	14,512	-	-
7	2026	-	(4,400)	-	2026	4,400	-	-
8	2027	-	(5,900)	-	2027	5,900	-	-
9	2028	-	(4,400)	(6,780)	2028	4,400	-	(6,780)
10	2029	-	(11,750)	(14,341)	2029	8,750	(3,000)	(14,341)
11	2030	-	(11,150)	(28,683)	2030	11,150	-	(28,683)
12	2031	-	(2,400)	(14,341)	2031	2,400	-	(14,341)
13	2032	-	(2,750)	-	2032	2,750	-	-
14	2033	-	(11,750)	-	2033	-	(11,750)	-
15	2034	-	(5,400)	-	2034	-	(5,400)	-
16	2035	-	(10,150)	-	2035	-	(10,150)	-
17	2036	-	(4,650)	-	2036	-	(4,650)	-
18	2037	-	(2,400)	-	2037	-	(2,400)	-
19	2038	-	(550)	-	2038	-	(550)	-
20	2039	-	-	-	2039	-	-	-
21	Total	$ 59,291	$ (136,306)	$ (64,146)	Total	$ 157,697	$ (37,900)	$ (64,146)

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Capital - Campbell 1 Early Retirement Cases

Retire Campbell 1 5/31/2024

Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
1	2020	9,644	9,268	(381)	-
2	2021	3,293	13,541	(200)	29
3	2022	1,050	5,257	(6,250)	-
4	2023	800	9,696	(6,415)	224
5	2024	250	11,252	(9,503)	-
6	2025	-	7,800	(2,550)	-
7	2026	-	4,420	(3,300)	-
8	2027	-	6,845	(4,050)	-
9	2028	-	7,394	(3,500)	-
10	2029	-	2,500	(3,879)	-
11	2030	-	1,050	(2,564)	-
12	2031	-	250	(250)	-
13	Total	$ 15,037	$ 79,273	$ (42,840)	$ 253

Retire Campbell 1 5/31/2025

Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
2020	9,989	9,268	(36)	-
2021	3,293	13,512	(200)	-
2022	3,810	5,257	(3,490)	-
2023	3,784	9,472	(3,431)	-
2024	800	11,252	(8,953)	-
2025	250	7,800	(2,300)	-
2026	-	4,420	(3,300)	-
2027	-	6,845	(4,050)	-
2028	-	7,394	(3,500)	-
2029	-	2,500	(3,879)	-
2030	-	1,050	(2,564)	-
2031	-	250	(250)	-
Total	$ 21,926	$ 79,020	$ (35,951)	$ -

Retire Campbell 1 5/31/2026

Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
14	2020	9,989	9,268	(36)	-
15	2021	3,293	13,512	(200)	-
16	2022	3,810	5,257	(3,490)	-
17	2023	4,073	9,472	(3,141)	-
18	2024	1,616	11,252	(8,137)	-
19	2025	800	7,800	(1,750)	-
20	2026	250	4,420	(3,050)	-
21	2027	-	6,845	(4,050)	-
22	2028	-	7,394	(3,500)	-
23	2029	-	2,500	(3,879)	-
24	2030	-	1,050	(2,564)	-
25	2031	-	250	(250)	-
26	Total	$ 23,831	$ 79,020	$ (34,046)	$ -

Retire Campbell 1 5/31/2028

Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
2020	10,025	9,268	-	-
2021	3,493	13,512	-	-
2022	7,300	5,257	-	-
2023	7,215	9,472	-	-
2024	9,753	11,252	-	-
2025	2,550	7,800	-	-
2026	2,050	4,420	(1,250)	-
2027	800	6,845	(3,250)	-
2028	250	7,394	(3,250)	-
2029	-	2,500	(3,879)	-
2030	-	1,050	(2,564)	-
2031	-	250	(250)	-
Total	$ 43,436	$ 79,020	$ (14,442)	$ -

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Capital - Campbell 2 Early Retirement Cases

Retire Campbell 2 5/31/2024

Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
1	2020	10,025	8,861	-	(407)
2	2021	3,530	11,739	37	(1,773)
3	2022	7,300	1,300	-	(3,957)
4	2023	7,500	800	285	(8,672)
5	2024	9,753	250	-	(11,002)
6	2025	2,550	-	-	(7,800)
7	2026	3,300	-	-	(4,420)
8	2027	4,050	-	-	(6,845)
9	2028	3,500	-	-	(7,394)
10	2029	3,879	-	-	(2,500)
11	2030	2,564	-	-	(1,050)
12	2031	250	-	-	(250)
13	Total	$ 58,200	$ 22,950	$ 322	$ (56,070)

Retire Campbell 2 5/31/2025

Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
2020	10,025	9,219	-	(49)
2021	3,493	13,271	-	(241)
2022	7,300	5,107	-	(150)
2023	7,215	3,800	-	(5,672)
2024	9,753	800	-	(10,452)
2025	2,550	250	-	(7,550)
2026	3,300	-	-	(4,420)
2027	4,050	-	-	(6,845)
2028	3,500	-	-	(7,394)
2029	3,879	-	-	(2,500)
2030	2,564	-	-	(1,050)
2031	250	-	-	(250)
Total	$ 57,878	$ 32,446	$ -	$ (46,573)

Retire Campbell 2 5/31/2026

Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
14	2020	10,025	9,219	-	(49)
15	2021	3,493	13,271	-	(241)
16	2022	7,300	5,107	-	(150)
17	2023	7,215	3,800	-	(5,672)
18	2024	9,753	1,300	-	(9,952)
19	2025	2,550	800	-	(7,000)
20	2026	3,300	250	-	(4,170)
21	2027	4,050	-	-	(6,845)
22	2028	3,500	-	-	(7,394)
23	2029	3,879	-	-	(2,500)
24	2030	2,564	-	-	(1,050)
25	2031	250	-	-	(250)
26	Total	$ 57,878	$ 33,746	$ -	$ (45,273)

Retire Campbell 2 5/31/2028

Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
2020	10,025	9,268	-	-
2021	3,493	13,512	-	-
2022	7,300	5,257	-	-
2023	7,215	9,472	-	-
2024	9,753	11,252	-	-
2025	2,550	4,800	-	(3,000)
2026	3,300	3,170	-	(1,250)
2027	4,050	3,706	-	(3,139)
2028	3,500	250	-	(7,144)
2029	3,879	-	-	(2,500)
2030	2,564	-	-	(1,050)
2031	250	-	-	(250)
Total	$ 57,878	$ 60,687	$ -	$ (18,333)

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

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Date: October 2021

Generation Operations - Capital - Campbell 1 & 2 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 1&2 5/31/2024				**Retire Campbell 1&2 5/31/2025**				
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
1	2020	9,644	8,861	(381)	(407)	2020	9,989	9,219	(36)	(49)
2	2021	3,293	11,739	(200)	(1,773)	2021	3,293	13,271	(200)	(241)
3	2022	1,050	1,300	(6,250)	(3,957)	2022	3,810	5,107	(3,490)	(150)
4	2023	800	800	(6,415)	(8,672)	2023	3,784	3,800	(3,431)	(5,672)
5	2024	250	250	(9,503)	(11,002)	2024	800	800	(8,953)	(10,452)
6	2025	-	-	(2,550)	(7,800)	2025	250	250	(2,300)	(7,550)
7	2026	-	-	(3,300)	(4,420)	2026	-	-	(3,300)	(4,420)
8	2027	-	-	(4,050)	(6,845)	2027	-	-	(4,050)	(6,845)
9	2028	-	-	(3,500)	(7,394)	2028	-	-	(3,500)	(7,394)
10	2029	-	-	(3,879)	(2,500)	2029	-	-	(3,879)	(2,500)
11	2030	-	-	(2,564)	(1,050)	2030	-	-	(2,564)	(1,050)
12	2031	-	-	(250)	(250)	2031	-	-	(250)	(250)
13	Total	$ 15,037	$ 22,950	$ (42,840)	$ (56,070)	Total	$ 21,926	$ 32,446	$ (35,951)	$ (46,573)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 1&2 5/31/2026				**Retire Campbell 1&2 5/31/2028**				
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
14	2020	9,989	9,219	(36)	(49)	2020	10,025	9,268	-	-
15	2021	3,293	13,271	(200)	(241)	2021	3,493	13,512	-	-
16	2022	3,810	5,107	(3,490)	(150)	2022	7,300	5,257	-	-
17	2023	4,073	3,800	(3,141)	(5,672)	2023	7,215	9,472	-	-
18	2024	1,616	1,300	(8,137)	(9,952)	2024	9,753	11,252	-	-
19	2025	800	800	(1,750)	(7,000)	2025	2,550	4,800	-	(3,000)
20	2026	250	250	(3,050)	(4,170)	2026	2,050	3,170	(1,250)	(1,250)
21	2027	-	-	(4,050)	(6,845)	2027	800	3,706	(3,250)	(3,139)
22	2028	-	-	(3,500)	(7,394)	2028	250	250	(3,250)	(7,144)
23	2029	-	-	(3,879)	(2,500)	2029	-	-	(3,879)	(2,500)
24	2030	-	-	(2,564)	(1,050)	2030	-	-	(2,564)	(1,050)
25	2031	-	-	(250)	(250)	2031	-	-	(250)	(250)
26	Total	$ 23,831	$ 33,746	$ (34,046)	$ (45,273)	Total	$ 43,436	$ 60,687	$ (14,442)	$ (18,333)

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-82:
2011 BART

Best Available Retrofit Technology (BART) Analysis of Control Options
For
Tri-State Generation & Transmission Association, Inc. – Craig Station Units 1 & 2

I. Source Description

Owner/Operator:	Tri-State Generation & Transmission Association, Inc.
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	10100222
Boiler Type:	Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired (Units 1 and 2)

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively.

Units 1 & 2: Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Fuel Gas Desulfurization (FGD) systems for the control of sulfur dioxide (SO_2) emissions. The boilers are equipped with ultra-low nitrogen oxide (NO_x) dual register burners with overfire air for minimization of NO_x emissions. The FGD and ultra low NO_x burner systems were required to be installed and fully operational by December 31, 2004 as a result of a consent decree with the Sierra Club (signed January 10, 2001).

Unit 3: Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of SO_2 and low-NO_x burners with overfire air.

All three units can use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for NO_x limits, effective January 1, 1997. Associated activities include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area. Unit 3 is not subject to BART.

Error! Reference source not found. below 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	4,417	4,417

Rating, MMBtu/Hr for coal		
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% PM – 99.6% PM_{10} – 99.4%	NO_x – 29.5%/54.7% SO_2 – 79.5% 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/PM_{10}-, uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See "Craig APCD Technical Analysis" for further details. Not based on actual testing.

Only Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and 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, July 30, 2010, November 23, 2010, and December 8, 2010. The submittals are included as "TriState BART Submittals".

II. Source Emissions

Tri-State estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or "Baseline" Emissions", to be conservative, was the average of two previous (2004, 2005) of emissions data in the July 31, 2006 analysis. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 2.

Table 2: Tri-State Craig Units 1 and 2 Baseline Emissions

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Average Emissions** (lb/MMBtu)
NO_x	5,190	0.278	5,372	0.271
SO_2	970	0.052	982	0.050
PM_{10}	80	0.006***	40	0.005***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO_2 emissions.
***The PM_{10} emission factor is determined from the most recent Title V permit compliance stack tests (January 2004).

III. Units Evaluated for Control

Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking sub-bituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. 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 1&2 will continue to burn "bituminous-like" coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 1&2 in the future. Similar to PSCo, Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

Table 3: Craig Station Coal Specifications (2008)

Coal Mine/Region	Colowyo	Trapper	Twentymile
Coal Rank Classification	Sub-bituminous, Class A	Sub-bituminous, Class A	Bituminous
H_2O (Moisture %)	17.42	16.7	9.62
Ash (%)	5.71	6.5	11.93
Sulfur (%)	0.37	0.44	0.52
Nitrogen (%)	1.35	~1.5	1.57
Heating Value (HHV Btu/lb)	10,392	9,800	11,084

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

Table 4: Uncontrolled emission factors for Craig BART-eligible sources[1]

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Unit 1	12	16.9	73.9	17.0

[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

Unit 2	12	16.1	71.1	16.4

*SO_2 and PM/PM_{10} factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006 – 2008). Please refer to "Craig APCD Technical Analysis" for more details.

IV. BART Evaluation of Units 1 and 2

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

Wet FGD Upgrades – As discussed in EPA's BART Guidelines[2], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the wet FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Craig Units 1 and 2 if technically feasible. These upgrades include:
-Elimination of bypass reheat
-Installation of liquid distribution rings
-Installation of perforated trays
-Use of organic acid additives
-Improve or upgrade scrubber auxiliary equipment
-Redesign spray header or nozzle configuration

The current Operating Permit limits are depicted in Table 5.

Table 5: Craig Units 1 & 2 SO_2 Operating Permit Limits

	SO_2 limits (lb/MMBtu)			Reduction (%) Required
	3-hr rolling	30-day rolling	90-day rolling	90-day rolling
Units 1 & 2	1.2	0.160	0.130	90

The current Operating Permit also requires that 100% of the flue gas in the FGD be treated (Conditions 1.3.3 and 2.3.3) and that the Craig Unit 1 and 2 FGDs be designed to meet at least a 97.3% removal rate (Conditions 1.3.4 and 2.3.4).

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO_2 from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity

[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.

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 TriState, installed wet limestone FGD systems, on Craig Units 1 and 2 when the units began operations in 1980 and 1979, respectively. TriState 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, TriState submitted a SO_2 upgrade analysis to the Division on June 4, 2010 regarding potential upgrades for the wet FGD systems at Craig Station Units 1 and 2.

TriState 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, TriState determined that installation of perforated trays, described below, accomplished the same objective.

-*Installation of perforated trays:* Upgrades during the YEP included installation of a perforated plate tray in each scrubber module. The trays improve the absorption of SO_2 by increasing the contact between the flue gas and the limestone slurry. The trays also function like Slurry Distribution Rings by redirecting slurry from running down the absorber wall back to the flue gas flow stream.

-*Use of organic acid additives:* Organic acid additives such as Dibasic Acid (DBA) can be used to improve SO_2 removal efficiency by increasing scrubbing liquor alkalinity. This option was considered for Craig Units 1 and 2 during YEP; however, it was not selected for the following reasons:
1. DBA has not been tested at the very low inlet SO_2 concentrations seen at Craig Units 1 and 2.
2. DBA could cause changes in sulfite oxidation with impacts on SO_2 removal and solids settling and dewatering characteristics.
3. Installation of the perforated plate tray accomplished the same objective of increased SO_2 removal.

-*Improve or upgrade scrubber auxiliary equipment:* YEP included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:

1. Two vertical ball mills were installed for additional limestone processing capability for increased SO_2 removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high SO_2 removal rates.
2. Forced oxidation within the SO_2 removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
3. A ventilation system was installed for each reaction tank.
4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
5. TriState installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased SO_2 removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
7. Instrumentation and controls were modified to support all of the new equipment.

-*Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during YEP. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, TriState and the Division concur that there are not any technically feasible upgrade options for Craig Station Units 1 and 2. However, the Division has evaluated the option of tightening the SO_2 emission limit for Craig Units 1 and 2.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The control effectiveness of tightening the 30-day rolling emission limits on Craig Units 1 and 2 have been evaluated by the Division. The Division analyzed the baseline period (2006 – 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 6, to determine potential control effectiveness, if any. This information allows the Division to set a more relevant emission limit for Craig Units 1 and 2 using representative actual emissions.

Table 6: Craig Units 1 & 2 30-day rolling emission rates (baseline 2006 - 2008)

Unit	Maximum 30-day rolling emission rate (lb/MMBtu)	Average 30-day rolling emission rate (lb/MMBtu)
Craig Unit	0.081	0.052

1		
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 protocol[3], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM_{10}) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions at 0.10 lb/MMBtu (wet FGD).

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 7: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour	1	0.166	Mt. Zirkel Wilderness	207	---	---	123	---	---
	2	0.161							

[3] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

Wet FGD	1	0.150		207	206	1	123	123	0
	2	0.150		207	207	0	123	123	0
Wet FGD	1	0.120		207	204	3	123	123	0
	2	0.120		207	204	3	123	123	0
Wet FGD	1	0.110*		n/a					
	2	0.110*		n/a					
Wet FGD	1	0.100		207	203	4	123	123	0
	2	0.100		207	203	4	123	123	0
Wet FGD	1	0.070		207	202	5	123	122	1
	2	0.070		207	203	4	123	122	1
Combo	1	0.100		207	57	150	123	12	111
	2	0.100							

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Craig BART Modeling Summary" for more details.

Table 8: Visibility Results – SO_2 Control Options

SO2 Control Scenario	Boiler(s)	SO2 Emission Rate (lb/MMBtu)*	Output (@ 98th Percentile Impact)*	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour	1	0.166	3.73	---	---
	2	0.161			
Wet FGD	1	0.150	3.72	0.01	0%
	2	0.150	3.72	0.01	0%
Wet FGD	1	0.120	3.70	0.02	1%
	2	0.120	3.71	0.02	1%
Wet FGD	1	0.110*	3.70	0.03	1%
	2	0.110*	3.70	0.03	1%
Wet FGD	1	0.100	3.69	0.03	1%
	2	0.100	3.70	0.03	1%
Wet FGD	1	0.070	3.68	0.05	1%
	2	0.070	3.68	0.05	1%
Combo	1	0.070	1.17	2.56	69%
	2	0.070			

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Craig BART Modeling Summary" for more details.

Step 6: Select BART Control

There are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 and determined that a more stringent 30-day rolling SO_2 limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology. The tighter emission limits are achievable without additional capital investment. An SO_2 limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

B. Filterable Particulate Matter (PM_{10})

Craig Units 1 and 2 are each equipped with pulse jet fabric filter (PJFF) baghouses to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 9 shows the most recent stack test data (2004). Real-time data demonstrates that these baghouses are meeting >95% control. The Title V permit limit is 0.03 lb/MMBtu (Condition 1.1.3). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 9: Craig Units 1 and 2 Stack Test Results (2004)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM_{10}	0.006	0.005
PM_{10} Control efficiency	99.23%	99.35%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations. Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado's SIP for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements (4/19/01), as approved by EPA at 66 FR 35374 (07/05/01).

The Division has determined that the existing Unit 1 and 2 pulse jet fabric filter baghouses and the emission limit of 0.03 lb/MMBtu (PM/PM_{10}) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM_{10}.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

TriState 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

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: TriState 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 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 Units 1 and 2. Mobotec could not give TriState a definitive guarantee for reductions due to the variability in the quality of coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[4]. While ROFA is considered superior to OFA/SOFA alone, ROFA alone is not superior to LNB+OFA and is not expected to increase emissions reductions for Craig Units 1 and 2. The Division asserts that ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for these units, ROFA® technology is not considered further in this analysis.

[4] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

Neural network system combustion controls: TriState 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. 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 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. This 20-40% range includes units operating with LNB/combustion modifications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Craig Units 1 and 2. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

While a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for Craig, two retrofit SCR systems, the 0.07 lb/MMBtu controlled NO_x value is more expected, although TriState asserts that the units cannot achieve below 0.08 lb/MMBtu. See "TriState BART Submittals" for more details. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. SCR is a technically feasible alternative for Craig Units 1 and 2.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not

been demonstrated on a full-size pulverized coal-fired boiler[5] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[6] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

LNB/SOFA/LNB+SOFA: Craig Units 1 and 2 are already equipped with ultra-low NO_x burners with over-fire air (ULNB+OFA) as part of a consent decree. Requirements for these control systems were adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements," dated April 19, 2001. Table 1 illustrates that these systems achieve 39.7% and 41.1% NO_x reductions (based on actual emissions) on Units 1 and 2, respectively.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[7]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

TriState 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: 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

[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
[7] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf
[8] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

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: TriState stated in the May 14, 2010 submittal that based on the boiler configuration, TriState could expect a continuous NO_x reduction performance with SNCR technology in the range of 10 – 15%. This is based on TriState'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. TriState 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. 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: TriState 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. TriState did not specify if this estimate was a 30-day rolling averages, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu[9]or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve NO_x reduction efficiencies greater than 85% with emission

[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.

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, The Division may evaluate tighter emission limits in future RH planning periods if SCR is determined to be BART for either Craig Unit 1 or 2. At this time, the Division accepts Tri-State's estimates of 0.08 lb/MMBtu on a 30-day rolling average. Table 10 depicts a comparison of SCR control efficiencies. The Division adjusted TriState's estimate to 0.07 lb/MMBtu based on the reasoning above.

Table 10: SCR Control Efficiency Comparison

Unit	Baseline (lb/MMBtu)	Control Efficiency (%)		Resultant Emissions (lb/MMBtu)	
		TriState Estimate	Division Estimate	TriState Estimate (annual average)	Division Estimate (annual average)
Craig Unit 1	0.278	71.4	74.9	0.080	0.070
Craig Unit 2	0.271	70.5	74.0	0.080	0.070

Table 11 summarizes each available technology and technical feasibility for NO_x control.

Table 11: Craig Units 1 and 2 NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners/Ultra-low NO_x burners (LNB/ULNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed
Air Staging – 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	~15%	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

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

[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.

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.[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.

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.[12] 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.[13] The TriState-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

[11] Bryk and Kleisley, 2000. "First Commercial Application of DRB-4Z™ Ultra-Low NOx Coal-Fired Burner." Presented to POWER-GEN International 2000. November 14-16, 2000. Orlando, Florida.
[12] NeuCo White Papers and Case Studies. http://www.neuco.net/library/case-studies/default.cfm and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NOx Emission Control Cost and Technical Feasibility Information."
[13] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.
[14] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

capital costs and capacity factor. [15,16] It should be noted that TriState 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. TriState 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 TriState. The costs for these two items are higher than other Colorado facility estimates. Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division accepts TriState'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 TriState is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. TriState'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

[15] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[16] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[17] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[18] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[19] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[20] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[21] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

SNCR	15	4,412	0.236	0.27
SCR	74.9	1,305	0.070	0.08

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	0.07

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	3,893	$25,036,709	$6,432	$6,708

Table 15: Craig Unit 2NO_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	$6,299	$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

TriState 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 protocol[22], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO_2 BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels. For BART sources with more than

[22] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions at 0.10 lb/MMBtu (wet FGD control).

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

Table 16: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hour	1	0.352	Mt. Zirkel Wilderness	207	---	---	123	---	---
	2	0.345							
SNCR	1	0.236		207	192	15	123	123	0
	2	0.230		207	194	13	123	123	0
SCR	1	0.07		207	165	42	123	123	0
	2	0.07		207	166	41	123	123	0
Combo	1	0.07		207	57	150	123	12	111
	2	0.07							

Table 17: Visibility Results – NO_x Control Options

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hour	1	0.352	3.73	---	---	---
	2	0.345				
SNCR	1	0.236	3.42	0.31	8%	$12,327,922
	2	0.230	3.42	0.31	8%	$12,327,922
SCR	1	0.07	2.72	1.01	27%	$24,887,384
	2	0.07	2.75	0.98	26%	$25,652,365
Combo	1	0.07	1.17	2.56	69%	$19,537,034
	2	0.07				

Step 6: Select BART Control

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART Alternative 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 SNCR controls at the following NOx emission rates:

Craig Unit 1: 0.27 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.27 lb/MMBtu (30-day rolling average)

For SNCR at Units 1 and 2, 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: $4,877 per ton NOx removed; 0.31 deciview of improvement
- Unit 2: $4,712 per ton NOx removed; 0.31 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements, leads the state to this determination. 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. Although emission limits associated with SCR achieve better emissions reductions, the cost-effectiveness of SCR for this BART determination was determined to be excessive and above the cost guidance criteria presented above. 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.

Per Section 308(e)(2) of EPA's Regional Haze Rule, as an alternative to BART (or "BART alternative") it was proposed and the state agreed to a more stringent NO_x emissions control plan for these BART units that consists of emission limits assumed to be associated with the operation of SNCR for Unit 1 and the operation of SCR for Unit 2. These NO_x emission rates are as follows:

Craig Unit 1: 0.28 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.08 lb/MMBtu (30-day rolling average)

Unit 1's 0.28 lb/MMBtu NO_x emission rate equates to a 14% control and a NO_x reduction of 727 tons per year, which is slightly less than the 15% control and a NO_x reduction of 779 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.
Unit 2's 0.08 lb/MMBtu NOx emission rate equates to a 74% control and a NO_x reduction of 3,975 tons per year, which is much greater than the 15% control and a NO_x reduction of 806 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.
The total NO_x emission reduction resulting from the BART determination is 1,585 tons per year (779 + 806 = 1,585 tons per year). The total NO_x emission reduction resulting from the BART Alternative is 4,702 tons per year (727 + 3,975 = 4,702 tons per year). Given the far greater emission reduction achieved by the BART Alternative when compared to the BART determinations for the individual units, the state determines, in accordance with the federal Regional Haze regulations, that the BART Alternative emission rates are appropriate for Craig

Units 1 and 2 as providing greater reasonable progress than the application of BART as set forth in the federal BART Alternative regulation.

The state also evaluated the NO_x emission reduction associated with both units (Craig 1 & 2) in contrast to the existing NO_x rates, presumptive BART NO_x rate, source-by-source determination, and the final RH determination to determine the total NO_x reduction benefit. In the below table, the existing NO_x emissions from both units is 10,562 tons/year which is much lower than the existing presumptive BART emissions of 14,849 tons/year. The source-by-source BART determination resulted in NO_x emissions of 8,978 tons/year which is well above the 5,860 tons/year in NOx emissions calculated to result from application of the BART Alternative. These tons/year calculations provide an emissions based comparison to demonstrate that the Craig BART Alternative provides greater reasonable progress than, and is superior to, source by source BART for these units. The table below is illustrative for demonstration purposes only. The tons per year projections provide an emission based comparison and are not enforceable requirements.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-83:
2025 EIA Form 923

State	Facility Nai	Facility ID	Unit ID	Associated Year	Operating T	Sum of the	Gross Loac	Steam Loa	SO2 Mass (	SO2 Rate (l	CO2 Mass	CO2 Rate (	NOx Mass (	NOx Rate (l	Heat Input	Primary Fu	Secondary	Unit Type	SO2 Contr	NOx Contr	PM Control	Hg Control	Program Code
CO	Craig	6021	C1	2020	8511	8490.94	2517304		560.023	0.0431	2726442	0.105	3097.992	0.2329	25995872	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2021	8123	8119.01	2563445		573.766	0.0439	2751844	0.105	3095.465	0.2316	26238031	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2022	8413	8393.53	2797335		742.279	0.0518	2917219	0.1049	3492.321	0.2465	27814864	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2023	8083	8072.47	2015029		526.926	0.0474	2210610	0.105	2518.031	0.2337	21077513	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C1	2024	8541	8536.69	1824100		335.429	0.0325	2058659	0.105	2211.571	0.2218	19628748	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2020	7993	7961.83	2300379		517.033	0.0404	2562694	0.105	763.524	0.0618	24434513	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2021	8635	8628.91	2822038		476.124	0.0301	3177713	0.105	1014.748	0.0667	30298549	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2022	8427	8420.82	2629692		645.904	0.0451	2948921	0.105	987.563	0.0698	28117158	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2023	5582	5573.88	1245370		282.48	0.0381	1457229	0.105	401.375	0.0562	13894277	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C2	2024	8405	8400.47	1801957		302.703	0.0271	2209975	0.105	625.283	0.0587	21071487	Coal	Pipeline Na	Dry bottom	Wet Limes	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2020	7811	7789.23	2821877		1644.329	0.1077	3145100	0.105	3152.793	0.2047	29987627	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2021	7426	7415.67	2579840		1307.602	0.1058	2635046	0.1049	2731.044	0.2108	25124446	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2022	7708	7697.91	2783361		1714.714	0.1259	2837603	0.105	2973.326	0.2122	27055733	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2023	7624	7611.42	1981366		1195.702	0.117	2135790	0.105	2131.88	0.2023	20364134	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
CO	Craig	6021	C3	2024	6146	6137.68	1441766		666.086	0.0852	1610839	0.105	1495.032	0.1898	15358887	Coal	Pipeline Na	Dry bottom	Dry Lime F	Low NOx B	Baghouse		ARP, MATS

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-84:
2024 EIA Form 923

U.S. Department of Energy, The Energy Information Administration (EIA)
EIA-923 Monthly Generating Unit Net Generation Time Series File, 2024 Final Data
Sources: EIA-923 and EIA-860 Reports

Plant Id	Combined Heat And Power Plant	Plant Name	Operator Name	Operator Id	Plant State	Census Region	NERC Region	NAICS Code	Sector Number	Sector Name	Generator Id	Reported Prime Mover	Respondent Frequency	Net Generation (MWh)													
														Net Generation January	Net Generation February	Net Generation March	Net Generation April	Net Generation May	Net Generation June	Net Generation July	Net Generation August	Net Generation September	Net Generation October	Net Generation November	Net Generation December	Net Generation Year To Date	Balancing Authority Code	YEAR
60219	N	Craig (CO)	Tri-State G & T Assn, Inc	30153	CO	MTN	WECC	22	1	Electric Utility	1	ST	M	194.852	164.236	159.884	86.688	100.346	129.110	144.740	137.814	121.411	121.222	94.922	140.477	1,503.93	WACM	2024
60219	N	Craig (CO)	Tri-State G & T Assn, Inc	30153	CO	MTN	WECC	22	1	Electric Utility	1	ST	M	185.996	134.270	159.552	129.604	118.365	129.458	141.814	137.824	126.164	122.724	80.365	132.87	1,618.91	WACM	2024
60219	N	Craig (CO)	Tri-State G & T Assn, Inc	30153	CO	MTN	WECC	22	1	Electric Utility	1	ST	M	226.238	165.044	46.248	0	63.346	124.830	173.748	164.116	122.393	41.794	90.473	81.046	1,300.97	WACM	2024

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-85:
Colorado Commission Decision No. C23-0437

Decision No. C23-0437

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 20A-0528E

IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN.

PHASE II COMMISSION DECISION APPROVING A COST-EFFECTIVE RESOURCE PLAN AND ADDRESSING TRI-STATE'S 2023 ELECTRIC RESOURCE PLAN FILING

Mailed Date: June 30 ,2023
Adopted Date: May 10, 2023

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I. BY THE COMMISSION

A. Statement

1. On February 13, 2023, Tri-State Generation and Transmission Association, Inc. (Tri-State) filed a report regarding the evaluation of bids and selection of a preferred resource portfolio for its 2020 Electric Resource Plan (ERP). The ERP Implementation Report or 150-Day Report was filed in Phase II of this ERP proceeding in accordance with the Commission's ERP Rules set forth at 4 Code of Colorado Regulations (CCR) 723-3-3600 *et seq*., and specifically Rule 3605.

2. By this Phase II Decision, we approve Tri-State's Revised Preferred Plan (RPP) as a cost-effective resource plan. The plan primarily includes the acquisition of a 200 MW wind resource through a power purchase agreement. The acquisition of the wind resource during this

resource acquisition period (RAP) will enable Tri-State to make incremental progress toward achieving 2030 and interim-year emissions reduction targets.

3. This Phase II Decision further addresses technical and policy considerations for Tri-State's next ERP. For instance, we address the emissions and economic modeling of the retirement of Tri-State's Craig Unit 3 and additional information Tri-State should submit in its forthcoming 2023 ERP filing, to ensure as robust a record as possible given economic and other uncertainties and lessons learned in this Proceeding.

4. Furthermore, based on the record in this 2020 ERP proceeding and all required considerations, including those in §§ 40-2-123, 40-2-124, 40-2-129, and 40-2-134, C.R.S., and as set forth in Rule 3605, we conclude that the Revised Preferred Plan portfolio includes a renewable resource that can be acquired at a reasonable cost and rate impact and with appropriate consideration to Best Value Employment Metrics; issues of energy security, economic prosperity, and environmental protection; and the energy policy goals of the State of Colorado.

B. Background

1. Electric Resource Planning for Tri-State

5. This Application addresses the first ERP filed by Tri-State before the Commission in response to legislative changes made by Senate Bill 19-236. SB 19-236 directed the Commission to promulgate ERP rules for wholesale electric cooperatives, and in so doing, to consider whether such cooperatives serve a multistate operational jurisdiction, have a not-for-profit ownership structure, and have a resource plan that meets the energy policy goals of the State.[1]

[1] *See* § 40-2-134, C.R.S.

6. The Commission adopted amendments to the ERP Rules at 4 Code of Colorado Regulations (CCR) 723-3-3600, *et seq* of the Rules Regulating Electric Utilities[2] which set forth a process in Rule 3605 under which the Commission would review Tri-State's ERP in a manner that reflected the time-tested Phase I and Phase II process applied to investor-owned utilities, with an additional pre-filing assessment of existing resources which provided an opportunity for education of the parties and the Commission as to Tri-State's system and operations.[3]

7. In accordance with Rule 3605, Tri-State assesses the need for additional resources given its energy and demand forecasts, existing resources, planning reserve margins, and other factors, including statewide goals to reduce greenhouse gas emissions, in Phase I of the ERP proceeding. Tri-State is also directed to set forth a plan for acquiring resources either through a competitive process or an alternative method of resource acquisition, and to provide bid policies, requests for proposals (RFPs), model contracts, and criteria for bid evaluation, as necessary. Phase II begins after the Commission issues its Phase I decision.

8. Pursuant to Rule 3605(h)(II), the Commission must consider certain public interest and statutory criteria in its Phase II decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan. We describe these briefly here.

9. Pursuant to §§ 40-2-123 and 40-2-124, C.R.S., the Commission considers renewable energy resources, energy efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission further considers resources that, among other characteristics, provide beneficial contributions to energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

[2] Proceeding No. 19R-0408E, Decision No. C20-0155, issued March 10, 2020.

[3] *See generally* Proceeding 20M-0218E.

10. Additionally, the Commission determines whether the utility has provided Best Value Employment Metrics (BVEM) in accordance with § 40-2-129, C.R.S.; certified compliance with the objective standards for the review of such metrics based on the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility. BVEM includes information the utility must request from bidders through the RFP process, including information on training programs, employment of Colorado workers, and long-term career opportunities.

11. With respect to the establishment of a cost-effective resource plan in Phase II, the Commission also considers the net present value of the revenue requirement for utility portfolios, with and without the net present value of the social cost of carbon dioxide emissions pursuant to § 40-3.2-106(3), C.R.S. Ultimately, in accordance with § 40-2-134, C.R.S., the Commission determines whether the final cost-effective resource plan meets Colorado's energy policy goals.

12. While recognizing these statutory obligations, we also note that Tri-State's inaugural ERP filed pursuant to Rule 3605 is being decided during a time of significant uncertainty for the wholesale cooperative. This includes supply chain challenges[4]; the prospect of additional member departures that have been announced since the Phase I decision became final[5]; planned, but not yet confirmed, entry into an organized wholesale market[6]; and the potential for new opportunities for financial mechanisms under the Inflation Reduction Act (IRA).[7] Public comments, including those from representatives served by Tri-State's member cooperatives,[8] urge

[4] Tri-State ERP Implementation Report at 5.
[5] Conservation Coalition Comments at 18.
[6] Colorado Energy Office Comments at 4.
[7] COSSA/SEIA Comments at 6-7.
[8] *See*, *e.g.*, Public Comment of John Clark, Mayor of Town of Ridgway (April 10, 2023).

the Commission to consider these factors carefully. Moreover, the Commission recently approved postponing Tri-State's filing of its 2023 ERP from June 1, 2023, to no later than December 1, 2023.[9] All of these complex factors weigh into the Commission's decision, as set forth below.

2. Procedural History

13. On December 1, 2020, Tri-State filed its 2020 ERP in two volumes along with Direct Testimony of six witnesses and other attachments. Tri-State's application was subsequently supplemented in response to Decision No. C20-0820[10] and Staff's Notice of Deficiency.[11]

14. Tri-State previously announced its Responsible Energy Plan in January 2020, which included actions to reduce carbon dioxide emissions from resources owned and operated by Tri-State in Colorado by 90 percent by 2030, as compared to 2005 levels, including through planned retirements of the coal units located at Craig.[12] While Tri-State did not file its 2020 ERP as a Clean Energy Plan,[13] the ERP nonetheless reflects increases in renewable energy, decreases in carbon dioxide emissions, and coal unit retirements while also delaying investments in new gas-fired generation.

15. On February 2, 2021, Natural Resources Defense Council, Sierra Club, and Western Colorado Alliance (collectively, the Conservation Coalition) filed a Proposed Motion Requesting that the Commission Instruct Tri-State to Revise its Application (CC Motion). The Commission set a deadline for response to the CC Motion by Decision No. C21-0139-I, issued March 10, 2021.

[9] Proceeding No. 23V-0050E, Decision No. C23-0107, issued February 16, 2023.

[10] Proceeding No. 20M-0218E, Decision No. C20-0820, issued November 25, 2020.

[11] Staff's Notice of Deficiency was filed on January 25, 2021, and Tri-State's supplemental direct testimony and attachments were filed on February 12, 2021.

[12] Hearing Exhibit (HE) 101, Direct Testimony and Attachments of Brad Nebergall, at Att. BN-1.

[13] Settlement Agreement at ¶ 2.2.

16. Also pursuant to Decision No. C21-0139-I, the following parties to this Proceeding are intervenors as of right: the Office of the Utility Consumer Advocate (UCA), the Colorado Energy Office (CEO), and Trial Staff of the Commission (Staff). Permissive intervenors include the Big Horn Rural Electric Company, Carbon Power & Light, Inc., High West Energy Inc., Wheatland Rural Electric Association, Wyrulec Company, Inc., Niobrara Electric Association, High Plains Power, Inc., and Garland Light & Power Co. (collectively, Wyoming Cooperatives); Poudre Valley Rural Electric Association, Inc. (Poudre Valley), Empire Electric Association, Inc. (Empire), Highline Electric Association (Highline), K.C. Electric Association (K.C.), Morgan County Rural Electric Association (Morgan County), Mountain View Electric Association, Inc. (Mountain View), Southeast Colorado Power Association (Southeast), and Y-W Electric Association, Inc. (Y-W) (collectively, Joint Cooperative Movants); Colorado Solar and Storage Association and Solar Energy Industries Association (COSSA/SEIA); the Conservation Coalition; Colorado Independent Energy Association (CIEA); Southwest Energy Efficiency Project (SWEEP); Interwest Energy Alliance (Interwest); Western Resource Advocates (WRA); International Brotherhood of Electrical Workers, Local No. 111 (IBEW Local 111); and Vote Solar. Delta-Montrose Electric Association was granted intervener status for a limited purpose.[14]

17. In responses to the CC Motion, parties proposed various alternative scenarios that we found could enhance the record of this Proceeding, and Tri-State set forth an alternative proposal in which additional scenarios could be modeled subject to modifications to the procedural schedule. Decision No. C21-0263-I, issued April 30, 2021, directed Tri-State to confer with parties

[14] A Motion to Intervene Out of Time filed by the Office of Just Transition was denied by Recommended Decision No. R21-0682-I, issued November 1, 2021.

and to submit a consensus proposal for a procedural schedule that would accommodate the modeling of up to five additional scenarios.

18. On June 8, 2021, the Commission issued Decision No. C21-0334-I. The Application was deemed complete for purposes of § 40-6-109.5, C.R.S., and referred to an Administrative Law Judge (ALJ).

19. Tri-State submitted Supplemental Direct Testimony reflecting additional scenario modeling on September 28, 2021.

20. Answer Testimony was filed by CEO, CIEA, Conservation Coalition, Interwest, Staff, SWEEP, UCA, and WRA on November 23, 2021.

21. Cross-Answer Testimony was filed by CEO, Conservation Coalition, Interwest, SWEEP, and WRA on January 4, 2022.

22. On January 4, 2022, Tri-State filed Rebuttal Testimony of four witnesses. Attached to the rebuttal testimony of Lisa K. Tiffin, Tri-State submitted as Highly Confidential Attachment LKT-4, a Verification Workbook (Verification Workbook) produced consistent with the March 2021 Clean Energy Plan Guidance (CEP Guidance) developed by the Colorado Department of Public Health and Environment's (CDPHE) Air Pollution Control Division (APCD).

23. On January 14, 2022, CDPHE filed its Motion for Limited Participation. The Motion was granted by Decision No. R22-0109-I, issued on February 23, 2022.

24. On January 18, 2022, Tri-State filed a Joint Motion to Approve Unopposed Comprehensive Settlement Agreement (Joint Motion). The Settling Parties[15] stated that they had

[15] All parties except Vote Solar and Delta-Montrose Electric Association, which took no position.

reached a comprehensive settlement (Settlement Agreement). The Settlement Agreement not only resolved certain modeling inputs and assumptions and set forth additional process for Phase II, but also established commitments to greenhouse gas emissions reductions, including interim reductions in years prior to 2030 that expressly survive the conclusion of this Proceeding. Furthermore, the Settlement Agreement also set forth commitments for its next ERP, including enhanced assumptions around demand-side management and beneficial electrification, and a commitment to host multiple stakeholder meetings around topics like scenario selection.

25. By Decision No. R22-0097-I, issued February 16, 2022, the ALJ issued clarifying questions regarding the Settlement Agreement. On March 2, 2022, Tri-State filed its Consensus Response to Interim Decision No. R22-0097-I (Consensus Response). The answers provided by the parties in the Consensus Response addressed all questions of the ALJ and the Joint Motion was approved by Recommended Decision No. R22-0191, issued March 28, 2022. No exceptions were filed, and it subsequently became the final decision of the Commission, thus initiating the Phase II process.

C. Tri-State's ERP Implementation Report and the RPP

26. Tri-State submitted its ERP Implementation Report pursuant to Rule 3605(h)(I) and the terms of the Settlement Agreement on February 13, 2023, or 150 days after bids were due. Tri-State requests the Commission find its RPP to be a cost-effective resource plan and approve it through this Phase II decision.

27. Pursuant to the Settlement Agreement as approved by the Commission, Tri-State presents a RAP of 2022 through 2030, and focuses only on acquisition of resources in 2025 and 2026. Tri-State received 274 eligible bid proposals and applied a screening process considering

completeness, economics, transmission interconnection, and non-price factors. Eleven bids were advanced to portfolio modeling.

28. Tri-State modeled five scenarios or portfolios: the RPP, which is Tri-State's preferred portfolio and would lead it to acquire a 200 MW wind power purchase agreement in 2025; Early GHG Reduction (EGHG), which expedites interim greenhouse gas emissions (GHG) targets by one year and acquires an additional 200 MW solar PPA in 2026; Reduced Load (RL), reflective of the departure of United Power; Wind Back-Up (Wind BKUP), in the event the primary bid fails; and Early Craig Retirement (EC3), which retires Craig Unit 3 at the end of 2026. Tri-State provided certain analyses related to the net present value revenue requirement, the impact of the Social Cost of Carbon (SCC) and the Social Cost of Methane (SCM), transmission interconnection, and reliability, for each portfolio. Tri-State also applied gas price and extreme weather event (EWE) sensitivities to each portfolio.

29. Tri-State recommends the Commission approve its selection of the RPP and the backup wind bid from the Wind BKUP portfolio should the primary bid fail, and affirm a December 31, 2029 retirement date for Craig Unit 3.[16] First, Tri-State states that it is in a capacity-long position until 2030 and resources acquired through Phase II are focused on incremental progress toward 2030 and interim-year emissions reduction targets rather than needed for resource adequacy or reliability. Second, Tri-State states that it must be cautious about acquiring new resources while the certainty and timing of member exists is still being reviewed in various regulatory proceedings. Finally, Tri-State argues that the RPP is the least-cost portfolio for Tri-State members. Tri-State states that 14 percent of end-use customers served by Tri-State members live below the federal poverty line and up to half of residential end-use customers suffer

[16] Response Comments by Tri-State at p. 39-40.

from some form of energy burden. Tri-State argues that maintaining a 2029 retirement date for Craig Unit 3 is essential for Tri-State to maintain sufficient dispatchable capacity until replacement gas capacity or other utility-scale dispatchable technologies are in place for reliability and resource adequacy, and to provide certainty to the Craig community and plant staff.

30. While Tri-State did not file a Clean Energy Plan,[17] Recommended Decision No. R22-0109-I, issued February 23, 2022, established the path by which the APCD of CDPHE would verify Tri-State's portfolios in Phases I and II. The APCD submitted Verification Workbooks for Tri-State's Phase II portfolios on March 22, 2023.[18] APCD's filing (1) verifies that CEP guidance and the Verification Workbook have been used properly to calculate emissions reductions requirements, including updates to expected member load requirements; (2) verifies that 2005 baseline emissions used are supported by historical data and reflect changes to the utility's customer base; and (3) verifies the projected emissions for calendar year 2030 produced by each portfolio. APCD finds that all portfolios achieve 81 to 83 percent emissions reductions by 2030 and Tri-State achieves a safe harbor from future Air Quality Control Commission regulations.

31. Additionally, Tri-State explains that it developed, in consultation with stakeholders, a set of robust reliability criteria and tested an extreme weather event (EWE) sensitivity on portfolios to ensure future resource additions can meet the necessary reliability and resource adequacy needs of member cooperatives.[19]

32. With its ERP Implementation Report, Tri-State included numerous attachments in response to provisions of the Settlement Agreement approved in Phase I, including documentation

[17] Settlement Agreement at ¶ 2.2.

[18] Decision No. C23-0198, issued March 22, 2023, granted an extension for the submission of the Verification Workbooks.

[19] ERP Implementation Report at 17 and Attachment E.

of updated modeling assumptions (Attachment B), bids advanced to modeling (Attachment C), maps of bids as compared to disproportionately impacted communities (Attachment G), and heat maps related to topics like emissions and renewable resource curtailment (Attachment H).[20]

D. Overview of Party Comments

33. The following parties timely filed comments on the ERP Implementation Report on March 30, 2023: CEO, the Conservation Coalition,[21] COSSA/SEIA, Interwest, Staff, the UCA, and WRA. Tri-State submitted its response to parties' comments on April 14, 2023. We have carefully considered all of these filings and summarize the principle themes of the parties' advocacy below.

1. CEO

34. CEO does not recommend that the Commission adopt a specific portfolio. However, it observes that the EGHG portfolio achieves earlier, and greater, cumulative emissions than the Revised Preferred Portfolio—and while the capital cost is $111 million higher, the EGHG portfolio is actually $576 million less when the SCC is applied. CEO further acknowledges the uncertainty of Tri-State's member load and the prospect of new federal funding opportunities, but observes that investments in additional renewable resources during this resource acquisition period may reduce cumulative GHG emissions over time. Finally, while supporting a retirement date of no earlier than summer 2027 for Craig Unit 3—and expressing concerns that the Craig community has been planning around the previously announced 2029 retirement date—CEO notes that

[20] While many of Tri-State's attachments are marked as confidential or highly confidential, per Rule 3605(h)(III), Tri-State shall file a proposal addressing the public release of bid information after the completion of Phase II.

[21] This time, comprised of the Natural Resources Defense Council and the Sierra Club.

additional renewable acquisitions may result in lower dispatch of the Craig unit when Tri-State joins an organized market.

2. COSSA/SEIA

35. COSSA/SEIA do not opine on the selection of a portfolio for Tri-State, and focus their comments on proposals to improve the competitive bid process in the 2023 ERP, both generally and due to new opportunities for generation asset ownership given the Inflation Reduction Act (IRA).

3. Conservation Coalition

36. Conservation Coalition recommends the Commission reject Tri-State's request to approve its RPP because of significant deficiencies in modeling related to the EWE sensitivity and its implications for the retirement of Craig Unit 3. Significantly, as we discuss further below, Conservation Coalition recommends the Commission decline to approve Tri-State's proposal to retire Craig Unit 3 by the end of 2029, and instead address the appropriate retirement date in the 2023 ERP. Conservation Coalition alleges significant defects in the Phase II modeling, including the construction and application of the EWE sensitivity, which Conservation Coalition argues includes reliability criteria and assumptions that have not been fully vetted, lack a basis in reality, and contravene common industry practices.

37. Conservation Coalition also recommends the Commission defer a decision on Craig Unit 3 to more fully consider federal funding options and because of emerging information about potential additional member departures, including not only United Power but also Northwest Rural Public Power District (NRPPD) and Mountain Parks. Even the RL portfolio overstates Tri-State's load, Conservation Coalition states. However, Conservation Coalition does not oppose the

Commission approving Tri-State's acquisition of the 200 MW wind project, arguing that energy from the new project will displace more expensive and polluting energy.

4. Interwest

38. Interwest recommends the Commission approve the EGHG portfolio rather than the RPP, as the latter is no longer the least-cost portfolio when the SCC and SCM are appropriately considered. Given recent gas price swings, Interwest also believes the EGHG portfolio has the greater price risk mitigation benefits. It specifically supports the 200 MW wind acquisition in eastern Wyoming and recommends the 200 MW solar acquisition in eastern Colorado also be acquired under the EGHG portfolio as it would contribute complementary operating characteristics and diverse locations.

5. Staff

39. Staff supports the RPP, or alternatively, the EGHG portfolio. Given modeling issues related to the EWE sensitivity and a range of uncertainties, Staff considers these to be the most realistic scenarios. While acknowledging the portfolios are similar in many ways, such as their system-wide GHG emissions and bids selected during the RAP, Staff explains that the RPP portfolio is less expensive than the EGHG portfolio based on NPVRR, but more expensive when SCC and SCM are considered.

40. Staff also raises concerns regarding the mechanics of Tri-State's Phase II modeling. There were significant variations between Phase I and Phase II which Tri-State did not explain, according to Staff. Staff also points out unexplained annual cost differences between portfolios that create questions as to the validity of Tri-State's selection of the RPP on cost grounds. Moreover, while stating its belief that Tri-State complied with the terms of the Settlement

Agreement around sensitivity modeling approaches, Staff critiques the limited information that Tri-State presents regarding the initial portfolio for each scenario, and suggests that repeated failures may indicate that the EWE sensitivity was not effectively constructed. In particular, Staff notes how annual planning reserve margins exceed 30 percent in all years beginning in 2025, despite a 15 percent minimum requirement.

41. However, Staff generally supports Tri-State moving forward with the acquisition of 200 MW of wind PPA to support compliance with GHG reduction requirements at a reasonable cost and given uncertainties Tri-State currently is operating under—including member load, future wholesale market participation, IRA tax credits and other funding opportunities, and the expectation of enhanced transmission capacity being available by 2028.

6. UCA

42. UCA supports Tri-State's proposal to select a 200 MW wind project given it is long on capacity and is experiencing uncertainty related to member load, supply chain issues, and federal incentives. UCA also raises that the 2023 ERP is fast approaching.

7. WRA

43. WRA argues that the Commission should refrain from approving any portfolio in its entirety in Phase II, as all portfolios were manually adjusted to meet the EWE sensitivity, and Tri-State did not present the original portfolios under base case conditions. WRA suggests this is problematic because the Commission cannot compare base case portfolios with the adjusted extreme weather portfolios to understand which incremental capacity additions are driven by the sensitivity, which is relevant to the decision regarding the Craig Unit 3 retirement date.

44. Ultimately, however, WRA recommends the Commission approve Tri-State's proposed acquisition of a 200 MW wind project in 2026. WRA asserts that despite flaws in the modeling, the portfolios indicate that deeper GHG emissions reductions are more cost-effective. Specifically, for the EGHG and EC3 portfolios, which have lower system-wide and cumulative emissions, the cost of incremental additional emissions reductions is well below the SCC. WRA thus recommends that Tri-State acquire an additional 200 MW solar resource in 2026.

E. Tri-State's Response to Party Comments

45. Tri-State points out that only 7 parties to the Settlement filed comments, with 21 parties filing no comments. While filed comments disagree regarding portfolio selection, they are largely supportive of Tri-State's proposal to acquire 200 MW of wind. Tri-State argues that parties' critiques are largely cherry-picking rather than holistically considering modeling outcomes, and it continues to support the RPP scenario as incorporating the most reasonable modeling assumptions. Tri-State also emphasizes that it is the first Colorado utility to incorporate binding interim-year and 2030 commitments for emissions reduction which it is meeting through the RPP. Moreover, Tri-State notes that an ERP is modeled using the best available information at any given point in time—future uncertainty in its load forecast does not warrant special action by the Commission, nor do modeling critiques warrant deferring a decision regarding the modeling of Craig Unit 3. Tri-State believes the best way to address uncertainty is to adopt the RPP, which reflects a reasonable path forward given current circumstances.

46. Tri-State further argues that it deserves the opportunity to fully prepare and present its 2023 resource plan as established by Rule 3605, and that the Commission should not take action on its 2023 ERP at this time. Tri-State raises concerns that not all parties have addressed the same issues; that the Commission does not have a full and comprehensive record on which to address

matters pertaining to the 2023 ERP; and accordingly, it would give a small subset of parties a disproportionate voice to make findings here. Finally, Tri-State argues that various items are already established for its 2023 ERP through the Settlement Agreement, and that it has been engaged in stakeholder discussions on that filing since January 2023, making additional Commission intervention unnecessary and potentially devaluing its collaborative stakeholder efforts. Ultimately, Tri-State asks the Commission to reject requests by parties to provide additional direction for its 2023 ERP.

F. Discussion, Findings, and Conclusions

1. Cost Effective Resource Plan

47. In consideration of the comments of all parties and given the broader perspective of the issues raised throughout this Proceeding, we approve Tri-State's selection of the RPP as the cost-effective resource plan. Acquiring 200 MW of wind through a power purchase agreement represents a no-regrets path forward, at a reasonable cost and rate impact to Tri-State members and with carbon emissions reduction benefits, given the uncertainties Tri-State has faced during this ERP. We further find that Tri-State has adequately considered statutory requirements for §§ 40-2-123, 40-2-124, and 40-2-134, C.R.S., set forth in Rule 3605, including environmental and social factors and insulation from fuel price increases through the focused competitive bid process and the selection of a renewable resource, and that the RPP supports the energy policy goals of Colorado in putting Tri-State on the path to achieve 80 percent reduction of greenhouse gas emissions by 2030.

48. While an additional solar acquisition consistent with the EGHG portfolio could potentially also be cost-effective as compared to continuing to utilize coal generating units which, as we describe below, have significant direct expenses, we agree with Tri-State that such an action

is premature at this time as the process and timeline of member departures remains complicated and uncertain.

49. However, while approving Tri-State's RPP overall, we are not prepared to endorse Tri-State's decision to retain the December 31, 2029, retirement date for Craig Unit 3 as final based on the record in this Proceeding. As explained in more detail below, parties have made a reasonable showing that an earlier retirement of Craig Unit 3 might be preferrable for emission reductions and economic purposes upon further analysis in Tri-State's next ERP. Retirement before 2029 may also be shown to be feasible for Tri-State with respect to reliability and resource adequacy with more refined modeling and analysis. For example, we have concerns regarding the treatment of the EWE sensitivity in the Phase II modeling process in this ERP. At the same time, however, we recognize that the coal plant retirement timing decision also involves a host of other factors including providing adequate and timely host community assistance, on-site construction management issues, the cost and benefits of potential replacement power, load uncertainty, and the future value of capacity in evolving regional market structures. Accordingly, we choose to tread cautiously in this area at the current time and direct further modeling and presentation of information in Tri-State's 2023 ERP, as described below.

2. Best Value Employment Metrics

50. Rule 3605(h)(II)(C) states that the Commission's Phase II decision shall determine in accordance with § 40-2-129, whether the utility has obtained and provided best value employment metrics (BVEM) and taken certain other steps.[22] BVEM include the availability of training programs such as apprenticeships; the employment of in-state instead of out-of-state labor;

[22] The Commission has not yet initiated a rulemaking regarding BVEM, although it has committed to do so in response to a legislative audit in July 2022.

long-term career opportunities; and industry-standard wages, health care, and pension benefits. Tri-State's bid evaluation process treated BVEM as a qualitative or non-price factor within the "community stewardship" category, which was considered along with counterparty profile, project feasibility, and project capability.[23] Tri-State also presented a ranking approach for reviewing non-price factors and submitted the documentation provided for bids advanced to modeling in Highly Confidential Attachment F to its ERP Implementation Report.

51. No comments were filed suggesting deficiencies in the BVEM data that was provided by bidders. IBEW Local #111 is a party to this proceeding and did not provide comments on the sufficiency of the materials in the ERP Implementation Report. Upon review of the materials and the bid process, particularly Highly Confidential Attachment F, we find that Tri-State has complied with Rule 3605(h)(II)(C), and in accordance with § 40-2-129, Tri-State has provided BVEM and objective standards for how it evaluated BVEM as between bids. As Tri-State has not proposed to construct or expand a generating facility, it has not proposed any PLAs.

3. Modeling, Bid Evaluation, and Plan Development

a. Extreme Weather

52. Parties raise various concerns about the content and application of the EWE sensitivity in the 2020 ERP and recommend modifications to the 2023 ERP.

53. Conservation Coalition argues that Tri-State's target reliability criteria are uncommon and lack support; the assumptions of the EWE lack support and are not reflective of historical experience; and the EWE sensitivity modeling led to implausible outcomes, including excessively high planning reserve margins. Moreover, Conservation Coalition states that Tri-State

[23] Tri-State 150-Day Report, pp. 12-13.

modified each modeling run to meet the EWE and did not present "base" portfolios, in contrast with typical resource planning practices. In its next ERP, Conservation Coalition argues that the Commission should direct Tri-State to make significant changes to EWE modeling, including implementing a detailed, four-step probabilistic assessment or at minimum, presenting portfolios with and without the sensitivity applied, and incorporating more realistic and better-documented assumptions.

54. Both Staff and WRA note that this issue is appropriately addressed in Tri-State's upcoming ERP, and state that stakeholder discussions are already revisiting how to define the EWE to better reflect weather conditions, duration, renewable resource performance, and other factors.

55. Tri-State explains that the EWE sensitivity was incorporated in the Settlement Agreement and then more specifically described as part of its Consensus Response. Tri-State contends it communicated frequently with the parties, but no parties expressed concerns with or suggested alterations to reliability criteria before it initiated modeling. Moreover, Tri-State alleges that Conservation Coalition misrepresents how it presented the portfolios, indicating that the sensitivity analysis was applied only to the dispatch and not to capacity expansion itself. Tri-State further rejects requests from parties that direct it to modify its EWE sensitivity modeling in specific ways in its next ERP, arguing that the Commission has an incomplete record here and that stakeholder discussions are ongoing leading up to the 2023 ERP.

56. Broadly, we have been pleased with the work that parties have done to develop a robust record for this Proceeding and to come together through the Settlement Agreement and other activities. We do not believe that disagreements around the EWE sensitivity undermine what has been achieved through this ERP process. However, discussion around this issue reveals the need for more transparent and detailed information around the treatment of sensitivities and

reliability indicators to be presented with sufficient timeliness to enable robust evaluation by the parties and by the Commission. While we decline to adopt the specific remedies the Conservation Coalition recommends with regard to EWE modeling, we direct Tri-State to present in the direct case of its 2023 ERP thorough descriptions of and justifications for all assumptions used in its modeling of an EWE, including its impact on load, its duration, its frequency, its geographic scope, the technology and operational options available to the model (e.g., market purchases both before and after joining an RTO), and any anticipated reduction in output from all generator types during the EWE. Tri-State should also discuss any probabilistic modeling applied in weather sensitivities or describe in its direct case the limitations it faces in doing so.[24]

57. We note that some parties have recommended that the parameters used in modeling an EWE should be based on historical events. While we agree that there must be some anchoring of EWE parameters to history, recent experience in Colorado suggests that history may not be fully predictive of future weather extremes given climate change, and an EWE that merely replicates past heat waves or winter storms might be an insufficient test of the resource adequacy of the portfolios under consideration in future ERPs.

58. Finally, we agree with parties that one role of a sensitivity analysis is to present results with and without the sensitivity applied. Without a full understanding of the cost, environmental and reliability characteristics of each portfolio under the base case, neither the Commission nor the parties can understand the many tradeoffs involved in selecting an alternate portfolio that may exhibit superior characteristics in response to a sensitivity run. Accordingly, in its 2023 ERP, we direct Tri-State to present the modeling results of portfolios under sensitivity

[24] Tri-State Response Comments, p. 33.

conditions as additions to, not substitutions for, the results of portfolio performance under base case assumptions.

b. Load Reduction

59. Tri-State's portfolios include a base load profile, with the exception of the RL portfolio, which removes load attributable to United Power.

60. Parties, including Staff and WRA, acknowledge the uncertainty caused by the prospect of member cooperatives departing the Tri-State system.

61. Conservation Coalition specifically contends that the Commission should not make a decision on key issues in the 2023 ERP, such as the retirement date for Craig Unit 3, given the prospect of member departures. United Power and NRPPD filed non-conditional notices of withdrawal from Tri-State at the Federal Energy Regulatory Commission on April 29, 2022, and Mountain Parks announced an intent to exit in January 2023. Conservation Coalition states that these members represent at least 25 percent of Tri-State's load, meaning that even the RL scenario potentially overstates Tri-State's load. However, Conservation Coalition also acknowledges that the parties agreed upon certain load forecasts in the Phase I Settlement Agreement. Thus, it recommends that in the next ERP, Tri-State should use a load forecast for every scenario that removes all load from member cooperatives that have provided notice of intent to exit, or negotiated partial requirements contracts, as of May 1, 2023. It recommends further that the Company should be required to file a notification with the Commission for any load changes announced following that date.

62. Tri-State responds that an ERP is a decision made at a point in time, and that it is not possible to change every input at every time. Moreover, it argues that it would be inappropriate

to set specific requirements for the next ERP in this venue, with comments from a limited subset of parties and with an ongoing stakeholder process.

63. We find the uncertainty attached to Tri-State's load forecast to be a troubling aspect of this ERP that will extend into the next, which is fast approaching. For instance, notices of intent to withdraw from Tri-State are not guarantees that member cooperatives will depart the system and reduce Tri-State's resource obligations. Recognizing this uncertainty, we have approved Tri-State's acquisition of 200 MW of wind as a no-regrets opportunity. However, given the magnitude of load that may leave Tri-State's system, we are concerned that the load forecast be more robustly vetted in the next ERP. We request that Tri-State submit a load forecast that is indicative of anticipated member departures at the time of filing, and if this is not the baseline, Tri-State should address why not. Moreover, we direct Tri-State to propose a process to notify the Commission of material changes to the load forecast at any time such a change occurs before the due date for bids in any competitive solicitation proposed in the next ERP.

64. Furthermore, we note that the appropriate incorporation of distributed energy resources remains a work in progress for Tri-State, given its position as a wholesale cooperative. We recognize that pursuant to the Settlement Agreement, Tri-State submitted an informational filing regarding demand-side management and beneficial electrification.[25] We encourage Tri-State to further explore the potential benefits of strategically locating distributed energy storage within member cooperative territories, and to address their approach to this process as part of their description of their load forecast for the 2023 ERP.

[25] 2023/24 Colorado Demand-Side Management Plan (September 1, 2022).

c. Bid Evaluation Process

65. Staff and COSSA/SEIA raise concerns that out of 274 bids, only 11 were advanced through the screening process for modeling. In light of this, Staff suggests that Tri-State should provide better guidance to bidders in its next ERP. First, COSSA/SEIA recommends that Tri-State be required to provide more information to bidders on the thresholds, criteria, and outcomes of each bid evaluation step in the 2023 ERP. Bidders do not know what cost thresholds were used in the economic screen, for example, and which screens failed which bids. Second, COSSA/SEIA states that unlike investor-owned utilities, Tri-State is not required to notify bidders at day 45 whether their bids advanced to computer modeling and if not, why not. According to COSSA/SEIA, this process should be applied along with a dispute resolution process so that modeling errors can be corrected in a timely way. Third, COSSA/SEIA alleges that Tri-State only advanced 4 percent of bids whereas prior ERPs by Public Service Company of Colorado advanced 52 percent of bids in 2011 and 38 percent of bids in 2016. Because a smaller bid pool reduces flexibility, COSSA/SEIA urges the Commission to require that at least 25 percent of bids be advanced to modeling in the 2023 ERP. Finally, COSSA/SEIA contends that the IRA has changed the incentives for Tri-State to participate in its future competitive solicitations, because due to the "direct-pay" provisions of the IRA, it will now be able to monetize federal tax credits for renewable generators. This, COSSA/SEIA suggests, means that an independent evaluator is needed to oversee future ERPs.

66. Tri-State argues that comments provided by COSSA/SEIA are outside the scope of the Commission's decision in a Phase II proceeding, as they would impact Tri-State's next ERP. Tri-State states that it has already been engaged in discussions with parties regarding its Phase II process and lessons learned for evaluation of bids in the next ERP. Tri-State rejects the proposal

to advance a set number or percentage of bids to modeling because it may advance bids that are not viable given screening criteria, instead proposing to provide more guidance to bidders in future ERPs. Tri-State also opposes the request to provide additional insight at each bid screen to bidders given its limited resources. It does state that it is considering an independent evaluator, but it reserves the right to make that proposal based on discussion with stakeholders.

67. We share the concerns expressed by Staff and COSSA/SEIA regarding the limited bids advanced to modeling and the limited information that Tri-State has thus far provided about the factors that resulted in only four percent of bids being advanced to modeling. While we decline to require most of COSSA/SEIA's specific recommendations, we do agree that more information and transparency into the inner workings of the bid selection process is warranted. Accordingly, we ask Tri-State to work with interested stakeholders to attempt to arrive at mutually agreeable and practical level of information that can be provided in the 45-day report. At minimum, this report should include information on the number of bids that failed each screen, and the specific criteria within each screen that caused bids to fail. Such information will enable parties and the Commission to better understand the criteria that are causing bids to fail and assess whether any adjustments are advisable for future solicitations. We further request that Tri-State either propose as part of its 2023 ERP the selection of an independent evaluator to review its bid selection and modeling process in Phase II of that proceeding, or explain why, in its view, an independent evaluator is unnecessary.

4. Coal Unit Retirements

a. Craig Unit 3

68. The retirement of Craig Unit 3 on December 31, 2029, is essential for Tri-State to achieve emission reduction targets by 2030,[26] the date by which significant reductions in emissions must be achieved pursuant to a Clean Energy Plan for a Colorado investor-owned electric utility.[27] In this Proceeding, the parties stress in their comments that additional emission reductions could be achieved if Craig Unit 3 is retired before 2030. The Commission further received dozens of public comments from individuals identifying themselves as being served by Tri-State member cooperatives that asked the Commission to require Tri-State increase its use of renewable resources and accelerate the retirement of coal-fired generating units like Craig Unit 3 to as early as 2025.

69. Tri-State identifies December 31, 2029, as the optimal retirement date for 448 MW Craig Unit 3 in the RPP. It claims that this date is essential to maintain sufficient dispatchable capacity until replacement capacity is in place to meet reliability and resource adequacy needs in 2030 and that the Phase II modeling has served to highlight the importance of this unit remaining online through 2029 under current system conditions. Additionally, Tri-State explains that this will create continuity for the City of Craig and Moffat County, which it is engaging through a third-party facilitated stakeholder process to explore community assistance opportunities.

70. CEO recommends clear and firm closure dates for all Craig units, with at least two but ideally three years or more between the submission of workforce and community assistance plans and a plant closure. According to CEO, Tri-State submitted its workforce transition plan to the Office of Just Transition and is expected to submit an informational community assistance plan

[26] *See*, *e.g.*, ERP Implementation Report at Attachment D-1.
[27] § 40-2-125.5(3)(a)(I), C.R.S.

in the summer of 2024. CEO states that workers, the City of Craig, Moffat County, and Tri-State have been planning around a 2029 retirement date for Craig Unit 3. If the Commission leaves open modifying a date in Tri-State's 2023 ERP, CEO recommends the Commission at minimum specify the earliest and latest possible retirement dates for Craig Unit 3, and suggests the window of summer 2027 through December 31, 2029.

71. Conservation Coalition urges the Commission to delay a decision on the Craig Unit 3 retirement date to Phase I of the 2023 ERP, as setting a date in this Proceeding is not justified by the current modeling, including flawed load forecasts and sensitivities. However, Conservation Coalition argues that if the Commission decides to set the unit's retirement date in this Proceeding, it should be set no later than January 1, 2027. Conservation Coalition asserts that the member departures will make Craig Unit 3 financially and environmentally expensive surplus capacity as soon as the end of 2025. Furthermore, full consideration of the SCC and SCM makes the retirement of Craig Unit 3 by 2027 the lowest-cost option, and a more realistic version of the EWE scenario suggests that early retirement is preferable.[28]

72. Staff states that it does not oppose including a firm retirement date for Craig Unit 3 here, but also suggests that it may be appropriate to consider earlier alternatives and the Commission's decision-making may benefit from additional modeling. Staff states its agreement that Community Assistance and Workforce Transition Plans should be established at least two years before the actual retirement date and thus indicates that Craig Unit 3 should be retired no earlier than January 1, 2027.

[28] ERP Implementation Report, Attachment I at 3.

73. WRA finds the modeling of the EWE faulty to the point that it recommends that the Commission refrain from approving a retirement date for Craig Unit 3 until it has more robust and useful modeling results. WRA refers to ongoing discussions with Tri-State which are likely to lead to better data on which to base a retirement date decision in the 2023 ERP proceeding.

74. Tri-State disagrees with parties' characterizations of the modeling results. Tri-State contends that the model's selection of December 31, 2029, as the optimal retirement date for Craig Unit 3 across all portfolios despite its ability to select any time between 2026 and 2029 (except where an earlier retirement was forced) affirms its long-standing plans for retirement. Tri-State argues that Conservation Coalition inflates the importance of the EWE to support its dissatisfaction with the resulting retirement date; that achieving reliability metrics was a more significant factor in portfolio selection; and that Craig Unit 3 is necessary until additional firm replacement capacity is available. In response to parties suggesting that the retirement date be modeled in the 2023 ERP, Tri-State argues that such a delay would do a disservice to those affected by the closure and would achieve, at most, a date that is one or two years earlier than currently planned. It argues that this would make little sense since the unit is already retiring well in advance of its useful life and the RPP will achieve necessary emission reductions. Tri-State further points to administrative complexities in staging retirements at Craig Station.

75. We recognize that this Proceeding is being conducted at a time of significant uncertainty for Tri-State, and that there are factors extending beyond the scope considered here that influence Tri-State's judgement about when to retire Craig Unit 3. We are thus reluctant to substitute our judgement for that of the utility in this case. At the same time, we find that the modeling flaws identified by the Conservation Coalition, Staff, and others are significant, and render the record in this Proceeding inconclusive with regards to the optimal retirement date for

Craig Unit 3. We see our role as ensuring that this process provides sufficiently accurate and actionable information to support the retirement decision, even if factors external to the ERP process may play a significant role in that decision.

76. Selecting an optimal date to retire a fossil generating unit includes a complex constellation of financial, contractual, construction, and other decisions. In this instance, there are also the considerations of a fair transition for the Craig community, including at least two and ideally more than three years for plant closure.[29] In addition, while parties have proposed dates as early as 2027 for retirement, and there is some evidence suggesting that earlier retirement could produce economic benefits for Tri-State's member-customers, we are concerned about a variety of factors that may impact the costs of replacement power, ranging from supply chains to inflation. While we would have preferred to establish a specific date for retirement in this Decision, we cannot in good conscience do so given critiques of the modeling process and these uncertainties.

77. Because we find that the record in this Proceeding does not clearly support December 31, 2029, or any other date, as the optimal retirement date for Craig Unit 3, we will not affirm a retirement date for that unit in this Proceeding.[30] Instead, we will direct Tri-State to evaluate alternate retirement dates for Craig Unit 3 in its 2023 ERP filing. We further request that Tri-State continue to work with interested parties to refine modeling assumptions and practices in an attempt to forge as great a degree of consensus as possible, by using its model to analyze the benefits and costs associated with various retirement dates for Craig Unit 3, including identifying economically optimal retirement dates as part of the direct case it will file in its 2023 ERP. We

[29] HE 1103, Cross-Answer Testimony of Wade Buchanan Rev. 1 (January 4, 2022) at p. 6:12-18.

[30] We note here that Commissioner Plant's preference during deliberations was to select a date certain for Craig 3 retirement within this proceeding to provide certainty to the Craig community, to allow sufficient time for the development of a community transition plan in advance of the plant's closure, and to ensure sufficient time for the community to apply for community assistance grants funded by the Inflation Reduction Act.

anticipate that this additional modeling will provide important analyses and information that can be balanced against other considerations as part of the process of developing a reasonable and appropriate retirement date.

b. Springerville Unit 3

78. Conservation Coalition argues that Springerville Unit 3, which, unlike Craig Unit 3, is located in Arizona and not Colorado, is Tri-State's most expensive generating unit and that the Commission should therefore reject Tri-State's proposal to continue its operation until 2040. Conservation Coalition states that Tri-State chose this year because its contract with the Salt River Project (SRP) expires in 2036, and that Tri-State erred in failing to model its retirement on economic grounds.

79. Conservation Coalition argues both that supplemental modeling in Phase I showed that Springerville Unit 3 was uneconomic as early as 2022, despite potential contract penalties, and that Tri-State's primary responsibility should be to its members rather than to SRP. Conservation Coalition thus recommends the Commission direct that Tri-State allow Springerville Unit 3 to economically retire in any year in every scenario modeled in Phase I of its 2023 ERP, and that all such modeling should incorporate the Company's best estimate of costs associated with early retirement. In the alternative, it asks the Commission to instruct Tri-State to model at least one portfolio that requires the model to retire Springerville Unit 3 during the RAP to enable comparisons across portfolios.

80. Tri-State states that Conservation Coalition has failed to provide any factual support for its contention that an early retirement for Springerville Unit 3 would save Tri-State customers money or that the unit would be surplus capacity following the announced load departures. Tri-State also criticizes Conservation Coalition for failing to identify the additional financial costs

(which include financing and equity partner penalties) to Tri-State members of an early retirement, which it claims are correctly reflected in all portfolio modeling. It notes further that even in the RL portfolio, Springerville Unit 3 is forecast to operate through January 1, 2040. Finally, referring to paragraph 3.11.14 of the Settlement Agreement, Tri-State notes that it has already agreed through the Settlement Agreement to model stakeholder-requested reductions or eliminations of the dispatch of Springerville Unit 3 in at least one of the Phase I scenarios in the next ERP.

81. We agree with the parties that address Springerville Unit 3 in their comments that the facility is expensive for Tri-State to continue to operate, and that its early retirement should be modeled as part of the 2023 ERP. However, as Tri-State indicates, it has already committed to model stakeholder-requested reductions or eliminations of the dispatch of Springerville Unit 3 in at least one of the Phase I scenarios in its next ERP based on discussions with stakeholders.[31] Given the Settlement Agreement, we find it would be procedurally unfair to direct the specific actions requested by Conservation Coalition. However, we acknowledge the concerns raised by Conservation Coalition regarding the expense of Springerville Unit 3 and expect that Tri-State's next ERP will accurately reflect the costs associated with early retirement in its modeling.

5. Treatment of Federal Funding

82. Parties raised two primary issues related to federal funding in Tri-State's 2023 ERP. The first relates to the modeling of IRA tax credits. The second relates to the treatment of federal funding, including whether Tri-State should be encouraged to pursue it and if so, how it should be modeled in future cases.

[31] Settlement Agreement at ¶ 3.11.14.

83. As to the first issue, Staff states that since the IRA was passed in August 2022, significant tax credits and other funding opportunities now exist which apply specifically to not-for-profit entities like Tri-State. These credits may result in cost-effective bids in the next ERP solicitation. More specifically, Conservation Coalition notes IRA provisions that maintain certain tax credits until the later of either 2032 or the year in which annual GHG emissions from electricity production fall below 25 percent of their 2022 level, and recommends that the Commission instruct Tri-State to assume in its modeling that those tax credits continue for the duration of the analysis period it uses in its next ERP—presumably, at least 2040. Tri-State responds that it made best efforts to incorporate the impact of IRA tax credits into Phase II modeling, despite the tight timeframe, and it continues to evaluate IRA-related assumptions for the 2023 ERP.

84. As to the second issue, CEO states that Tri-State submitted to Senators Bennet and Hickenlooper and Representative Perlmutter a proposal for funding to study the feasibility of a Craig Energy Center to test and demonstrate clean and low-emission technologies. CEO recommends the Commission encourage Tri-State to pursue community assistance opportunities for the City of Craig and Moffat County, as identified in the stakeholder engagement process, and to pursue federal funding for just transition. Similarly, Conservation Coalition recommends that the Commission direct Tri-State to incorporate at least one portfolio in its next ERP regarding U.S. Department of Agriculture Section 22004 funding, as well as detailed information on applications, timelines, collaboration, and other federal funding opportunities for which it may be eligible.

85. Tri-State states that it appreciates and shares CEO's concerns regarding a just transition for affected communities but argues that CEO's recommendations have limited relevance to Phase II and that it is participating in the development of a facilitated Community Assistance Plan, in partnership with the Office of Just Transition, the City of Craig, Moffat County,

CEO, and UCA. Tri-State states that it already submitted a Workforce Transition Plan for Craig Station to OJT in December 2022 and has voluntarily provided information to the Commission regarding federal funding pursuits in Proceeding No. 23M-0053ALL. Ultimately, it argues that it need not be persuaded to seek funding and urges the Commission to reject parties' requests. Moreover, it notes that modeling federal funding opportunities in the next ERP may not be appropriate, as not all funding opportunities are generation-related, they require complex financial analysis, and Commission oversight may impede efforts to rapidly secure funding.

86. We agree with Staff and Conservation Coalition that the treatment of tax credits under the IRA is an emerging and potentially significant area, and ask Tri-State to specifically address related modeling assumptions in its next ERP. Beyond that, while the funding mechanisms and incentives established in the Infrastructure and Jobs Act and the IRA are anticipated to create significant opportunities for Tri-State and its members, we agree that it has strong incentives to pursue such funding on behalf of its members. Nevertheless, we do encourage Tri-State to pursue all relevant funding to support community transition and the broader clean energy transition, and direct Tri-State to provide a narrative description of all federal funding it has or intends to pursue as part of its direct case for the 2023 ERP.

6. Requests Not Explicitly Addressed

87. Various other concerns and suggestions were raised by parties in addition to the issues explicitly addressed in this Decision—including for example, procedural issues related to the next ERP. While we support and encourage continuous improvement towards transparency, we find that it is not necessary to address each of these items, many of which are premature. Any request not addressed in this Decision is denied.

7. Waiver of Rule 3605(h)(II)(A)

88. By its own motion, the Commission waives Rule 3605(h)(II)(A), which requires the Commission to issue a written decision on Phase II within 90 days after the receipt of the utility's ERP Implementation Report. While the Commission has completed its deliberations, it finds that additional time is necessary for the circulation of this Decision prior to issuance given the Commission's significant caseload at this time.

II. ORDER

A. It Is Ordered That:

1. The Commission approves as a cost-effective resource plan the Revised Preferred Plan presented by Tri-State Generation and Transmission Association (Tri-State) in its ERP Implementation Report filed on February 13, 2023, in accordance with the Electric Resource Planning Rules set forth at 4 *Code of Colorado Regulations* (CCR) 723-3-3600 *et seq*., consistent with the discussion above.

2. In its next Electric Resource Plan (ERP) filing, Tri-State shall incorporate modifications to its modeling and present in its direct case certain information, consistent with the discussion above.

3. Rule 723-3-3605(h)(II)(A) is waived, consistent with the discussion above.

4. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

5. This Decision is effective on its Mailed Date.

B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING May 10, 2023.

(S E A L)

THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

ATTEST: A TRUE COPY

Rebecca E. White,
Director

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-86:
Tri-State 150-Day Implementation Report

Colorado PUC E-Filings System



Tri-State Generation and Transmission Association, Inc.

2020 Electric Resource Plan

Phase II Implementation Report

PUBLIC VERSION

(Colorado Public Utilities Commission Proceeding No. 20A-0528E)

Notice of confidentiality. A portion of this document has been filed under seal.
Confidential information has been redacted from page 13.
Highly confidential information has been redacted from pages 24, 36, 47, 57-58, and 68.

February 13, 2023

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Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with 42 Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

This report is Tri-State's Phase II ERP Implementation Report. The report complies with Colorado Public Utilities Commission (CoPUC) Rule 3605(h) and Decision No. R22-0191 in Proceeding No. 20A-0528E issued March 28, 2022, approving the Unopposed Comprehensive Settlement Agreement (Settlement Agreement) filed with the CoPUC on January 18, 2022, concluding Phase I of Tri-State's 2020 Electric Resource Plan (ERP).

Tri-State's preferred cost-effective resource portfolio is the Revised Preferred Plan. The Revised Preferred Plan adds 200 MW of new wind in 2026, maintains the previously announced Craig 3 retirement at the end of 2029, and results in a generation portfolio that meets and slightly exceeds both the interim and 2030 GHG emissions reduction targets[1] for Tri-State's Colorado wholesale sales. The Revised Preferred Plan is also the least-cost portfolio for Tri-State Members.[2] Tri-State supports this portfolio, which reflects its Members' strategic directives to ensure reliable, affordable, and responsible service. Importantly, the Revised Preferred Plan portfolio will enable continued progress under Tri-State's Responsible Energy Plan, under which Tri-State is forecasting that by 2030 it will eliminate 100% of the CO_2 emissions from Tri-State-owned coal generation in Colorado and that 70% of the electricity used by its Members will come from clean sources.

Tri-State has selected the Revised Preferred Plan as a result of the portfolio's overall performance across the reliability, environmental, and financial categories analyzed and described in this report. Relevant economic and operational contexts are also important. During 2022 and continuing into 2023, many industries have faced significant inflationary and supply chain pressures, which create a difficult environment for resource procurements. Additionally, utilities face reliability challenges in retiring baseload power that will be replaced solely with intermittent resources—in some cases leading to unforeseen delays in baseload resource retirements.[3] Tri-State's aggressive, yet incremental, approach to its generation portfolio transition aims to avoid these pitfalls and continue to deliver the system reliability expected by its Members. This approach is even more important given extreme weather

[1] See 2020 ERP Phase I Settlement Agreement, Proceeding No. 20A-0528E, filed January 18, 2022; at section 3.3.4: "Tri-State agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): A twenty-six percent (26%) reduction in calendar-year 2025; a thirty-six percent (36%) reduction in calendar-year 2026; and a forty-six percent (46%) reduction in calendar-year 2027."

[2] Lowest PVRR, exclusive of SCoC and SCoM.

[3] *For example:* Ameren (Missouri) 1.1 GW plant, three years; Omaha Public Power District (Nebraska), 645 MW, three years; NiSource/NIPSCO (Indiana) 877 MW plant, two years; Alliant Energy (Wisconsin) 400 MW plant, 2.5 years and 1.1. GW plant, 18 months; WEC Energy Group Inc. (Wisconsin) 1.1 GW plant, 18 months; PNM San Juan (New Mexico) 847 MW plant, three months.

events that add resource adequacy pressure.[4, 5] Uncertainty around Tri-State's future load requirements, given certain Members' announced plans to exit Tri-State, affirms the benefits of a tempered approach to resource acquisition and generation changes in this Phase II process. The benefits of the Revised Preferred Plan over other portfolios are reflected in the analyses presented in this Phase II report.

Portfolio Analysis Summary

Tri-State modeled five portfolios for Phase II of the 2020 ERP: 1) the Revised Preferred Plan, 2) Early Greenhouse Gas Reduction (EGHG), 3) Reduced Load (RL), 4) Wind Back-up Bid (Wind BKUP), and 5) Early Craig 3 Retirement (EC3). The Revised Preferred Plan portfolio, and Wind BKUP, reflect input assumptions that Tri-State believes to be the most accurate, and reflective of its system operations and Members' needs. The EGHG and EC3 portfolios reflect stakeholder-driven modeling assumptions that narrowly seek to drive prescribed outcomes for Tri-State's generation portfolio. The RL portfolio provides potential indication of system changes that could result from a Member exit.

Tri-State remains in a capacity-long position until 2030.[6] Therefore, resources acquired through Phase II of the 2020 ERP are not necessary for ensuring ongoing resource adequacy and reliability. All else being equal, the addition of 200 MW of new wind in 2026 in the Revised Preferred Plan portfolio will only add to Tri-State's forecasted 597 MW-long capacity position in 2026. Procurements in this resource acquisition period (RAP) will support Tri-State in making incremental progress toward achievement of its 2030 and interim-year emissions reduction targets,[7] and will provide value to its Members through the addition of a low-cost renewable resource to the generation portfolio.

The Revised Preferred Plan also makes sense in light of certain Tri-State Members' notices that they intend to exit the cooperative and no longer purchase wholesale power from Tri-State. Until the relevant regulatory proceedings are concluded, it is possible that those exits (and the corresponding reductions in future capacity needs) may not occur or the timing of the exists may change; therefore, Tri-State must be cautious about pursuing new resources based on a load forecast that includes these Members.

Further, affirming the already announced retirement date for Craig 3 (December 31, 2029) is essential for Tri-State to maintain sufficient dispatchable capacity until replacement gas capacity or other utility-

[4] Colorado Public Utilities Commission, "Resource Adequacy Planning and Analysis: Investigation of Potential Best Practice RA Approaches to Account for Increasing Penetrations for Renewable Energy Resources, Climate Change, and Extreme Weather," November 30, 2022. Available: https://drive.google.com/file/d/10PkMMJFMaTmFwOOjWfVvSk-d5575d6HU/view?usp=share_link.

[5] Western Electricity Coordinating Council (WECC), "2022 Western Assessment of Resource Adequacy," November 1, 2022. Available: https://www.wecc.org/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf.

[6] See Table 2, Loads and Resources, submitted in the 2022 ERP Annual Progress Report filed December 1, 2022 in Proceeding No. 20A-0528E.

[7] See 2020 ERP Phase I Settlement Agreement, Proceeding No. 20A-0528E, filed January 18, 2022; at section 3.3.4: "Tri-State agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): A twenty-six percent (26%) reduction in calendar-year 2025; a thirty-six percent (36%) reduction in calendar-year 2026; and a forty-six percent (46%) reduction in calendar-year 2027."

scale dispatchable technologies are in place to meet reliability and resource adequacy needs in 2030. The modeling conducted in Phase II has served to further highlight the importance of this unit remaining online through 2029 under current system conditions. Furthermore, maintaining continuity in the previously announced plans for the plant will provide needed certainty and assurance to the Craig community and the plant staff who are commendably working to ensure safe and reliable plant operations continuously through the period leading up to the plant's closure. In partnership with state and local leaders, Tri-State is launching a third-party facilitated stakeholder engagement process in 2023 to explore community assistance opportunities for the City of Craig and Moffat County, in preparation for plant closure. The previously announced plant retirement date allows sufficient time for that process to conclude, for Tri-State to evaluate the opportunities presented and make subsequent determinations related to community support in light of overall business conditions and Member expectations, and offer necessary lead-time for related planning efforts in advance of plant closure.

The EC3 portfolio results, by contrast, demonstrate the significant risks presented by aggressive pursuit of plant retirement without regard to operational, financial, and reliability realities. Notably, under the forced retirement window of the EC3 portfolio, the model delayed retirement of Craig 3 until the last possible date (January 1, 2027), while all other portfolios (none of which included a forced retirement window for Craig 3) selected to retain the December 31, 2029 announced retirement date for Craig 3. As a result of the EC3 portfolio's forced early retirement of Craig 3 (in addition to the constraint common to all portfolios that allows no new gas generation before 2030), the EC3 portfolio also diverged from the other portfolios in the amount of new resources forecasted to be brought online during the RAP. The EC3 portfolio results in the addition of an unrealistic and costly amount of new hybrid renewable-storage resources to meet reliability metrics. Further, the availability of such resources from experienced bidders at the size and locations needed, at a competitive cost, is uncertain and likely to come with significant curtailment costs and a need for additional third-party transmission capacity reservations. Retirement of dispatchable coal resources cannot be replaced solely with semi-dispatchable 4-hour batteries and keep reliability, affordability, and responsibility in balance; other dispatchable technologies—new or emerging—will be required.

Tri-State considered the Social Cost of Carbon (SCoC) and Social Cost of Methane (SCoM) when determining which Phase II Portfolio to support, and carefully compared all the portfolios against the EC3 portfolio, which resulted in the lowest greenhouse gas (GHG) emissions in 2030. This included review of the environmental and financial comparisons shown in the Comparative Analysis section of this report. Tri-State has taken these comparisons into significant account in determining that the Revised Preferred Plan portfolio in Phase II is the best course of action at this time. While the Reduced Load portfolio meets the 80% GHG emissions reduction target in 2030 with the updated baseline, given the significantly lower load forecast, the model does not select any renewable additions in the RAP for this portfolio, resulting in a system mix in 2030 with less renewable resources and higher average rates of emissions and water usage per MWh when compared to other portfolios. While this scenario achieves the lowest present value of revenue requirements (PVRR), the low PVRR is driven by a possible reduction in Member load that is currently uncertain as explained above. Importantly, the Revised Preferred Plan portfolio is forecasted to not only meet, but slightly exceed, Tri-State's Settlement Agreement targets for emissions reductions in 2025, 2026, 2027, and 2030.[8] On balance with reliability

[8] See Table 11.

and affordability expectations of Tri-State Members, the risks associated with the assumptions and outcomes of other portfolios that model slightly higher emissions reductions or lower SCoC and SCoM do not outweigh these factors.

Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data shows fourteen percent of the end-use customers served by Tri-State Members live below the federal poverty line, and up to half of the residential end-use customers suffer from some form of energy burden. The Revised Preferred Plan is the least-cost portfolio, having the lowest PVRR, exclusive of SCoC and SCoM. While the EC3 portfolio achieves the greatest percentage reduction in Colorado GHG emissions in 2030 among the portfolios,[9] it does so at the highest PVRR of the portfolios modeled. Similarly, the EGHG portfolio achieves the lowest[10] system-wide CO_2 emissions in 2030, but has a higher annual revenue requirement from 2024-2026 than the Revised Preferred Plan portfolio. This is due, in part, to the EGHG portfolio selecting two resource additions during the 2025-26 period. Tri-State is not in a position to pursue significant changes to its generation mix at a time when it is capacity-long, as that would not only greatly compromise its ability to meet the core reliability needs of its Members, but would also likely cause significant undue financial burdens for Member-consumers.[11] Not only does the Revised Preferred Plan meet essential reliability and affordability goals, but it is also the responsible choice, delivering an 81% GHG emissions reduction in Colorado in 2030 (with respect to the 2005 baseline)[12] which aligns with Colorado policy.[13]

Additional details on the comparative analysis Tri-State completed to support its preferred portfolio selection can be found in the Comparative Analysis section of this report.

Addressing Commission Rule 3605(h)(II)

The Commission must consider the following factors in issuing a Phase II decision:

> *In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.*
>
> Phase II of Tri-State's 2020 ERP included a request for proposals (RFP) under which only emissions-free resources, located in any region of the Tri-State system, would be advanced to modeling. The Phase II portfolio analysis included, for the first time, modeling of new, aggressive energy efficiency targets agreed upon in the Settlement Agreement in Phase I of the 2020 ERP.

[9] RL portfolio excluded from comparison, due to dissimilar load modeled.
[10] RL portfolio excluded from comparison, due to dissimilar load modeled.
[11] Tri-State is subject to Federal Energy Regulatory Commission rate jurisdiction, as of September 3, 2019.
[12] See Attachment D-1.
[13] C.R.S. 25-7-105 (1)(e)(VIII)(I)

Colorado's energy security, economic prosperity, and insulation from fuel price increases are best supported by a Tri-State portfolio that is diverse in the type, size, location, and operations of generation. Tri-State developed, in consultation with stakeholders, a set of robust reliability criteria and tested portfolios' extreme weather event (EWE) sensitivities to ensure future resource additions can meet the necessary reliability and resource adequacy needs of its Members. The Revised Preferred Plan portfolio meets these rigorous standards, while providing sufficient time for continued planning toward a just transition for communities impacted by planned future coal plant closures. Approval of the Revised Preferred Plan portfolio also assures the continued economic prosperity of its Member systems, operating in Colorado and outside of Colorado, by not aggressively adding new resource procurements that are unnecessary at this time and would apply additional financial pressure to Members serving predominately rural communities.

The Revised Preferred Plan portfolio will advance the environmental objectives of the State of Colorado because it is forecast to achieve (and exceed) the Colorado GHG reduction targets agreed on in the Settlement Agreement. The GHG reductions were calculated using the Colorado Air Pollution Control District's (APCD) emissions workbook methodology.

In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.

Tri-State has provided best value employment metrics (BVEM) provided by bidders, for the bids advanced to modeling, in HIGHLY CONFIDENTIAL Attachment F.

Tri-State included evaluation of BVEM as a non-price factor in its bid evaluation, as described in the Bid Evaluation section below, consistent with the RFP and as discussed with stakeholders on April 26, 2022.

Tri-State intends to enter into a power purchase agreement (PPA) for the applicable generation facility, therefore the resource developer will be responsible for determining whether a project labor agreement will be used.

In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.

The Revised Preferred Plan is the most cost-effective portfolio modeled, having the lowest PVRR.[14] The Revised Preferred Plan portfolio also complies with all applicable rules and regulations in the state of Colorado, most importantly by achieving an 80% reduction in GHG emissions by 2030 while continuing to ensure affordable and reliable service.

[14] Excluding the Reduced Load portfolio.

In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.

The Revised Preferred Plan has the lowest PVRR among the portfolios modeled.[15] Tri-State considered the SCoC in its review of the portfolio modeling results as described above in the Portfolio Analysis Summary section of the Executive Summary above and in the Environmental Analysis and the Financial Analysis sections of the Comparative Analysis discussion below.

Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in ongoing stakeholder engagement in advance of and during the Phase II resource planning process. Numerous stakeholder groups representing a diverse set of interests participated in more than a dozen meetings in advance of Tri-State's filing of this Implementation Report. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform parties of key modeling inputs and assumptions, and facilitate dialogue on topics applicable to Phase II and, in some cases, future ERPs. These stakeholder meetings occurred between April 2022 and January 2023, covering the following topics:

1. April 26, 2022: Phase II Meeting 1 – EnCompass Benchmarking and Bid Evaluation Criteria[16]
2. April 27, 2022: DSM Meeting 1 – Program Updates, Idea-Sharing, Potential Study Status[17]
3. May 24, 2022: Phase II Meeting 2 – Modeling Assumptions and Potential Studies Status[18]
4. April 10, 2022: Developer Perspectives Meeting 1[19]
5. June 13, 2022: Developer Perspectives Meeting 2[20]
6. June 14, 2022: DSM Meeting 2 – Program Best Practices, Energy Efficiency Targets[21]
7. June 14, 2022: Phase II RFP Status Update Meeting
8. August 1, 2022: DSM Meeting 3 – DSM Plan Overview[22]
9. August 16, 2022: Discussion of Emissions Rates[23]
10. August 23, 2022: Discussion of Phase II Bid Detail for Commission Staff and UCA[24]
11. September 7, 2022: Discussion #1 on Organized Markets[25]
12. September 29, 2022: Phase II Meeting 3 – Modeling Assumptions[26]

[15] Excluding the Reduced Load Portfolio.
[16] Settlement Agreement sections 3.5.3., 3.5.4., 3.5.5., and 3.5.6.
[17] Settlement Agreement sections 3.6.3. and 3.11.5.
[18] Settlement Agreement sections 3.3.2., 3.3.4., 3.6.3., 3.6.9., 3.6.10., 3.7., 3.9., and 3.10.
[19] Settlement Agreement section 3.8.
[20] Settlement Agreement section 3.8.
[21] Settlement Agreement section 3.11.5. and 3.11.9.
[22] Settlement Agreement section 3.11.5. and 3.11.9.
[23] Settlement Agreement section 3.11.4.
[24] Settlement Agreement section 3.7.11.
[25] Settlement Agreement section 3.14.1.
[26] Settlement Agreement sections 3.6.9., 3.6.10., 3.7., and 3.10.

13. October 27, 2022: Phase II Meeting on EWE Results for Revised Preferred Plan Portfolio[27]
14. November 9, 2022: Discussion #2 on Organized Markets[28]
15. November 15, 2022: Phase II Meeting on EWE Results for Early GHG Reduction Portfolio[29]
16. December 6, 2022: Phase II Meeting on EWE Results for Reduced Load Portfolio[30]
17. January 5, 2023: Phase II Meeting on EWE Results for Craig 3 Early Retirement Portfolio[31]
18. January 19, 2023: Phase II Meeting on EWE Approach for Reduced Load Portfolio and eGRID Rates for GHG Analysis[32]

Several e-mail communications and updates to stakeholders also occurred in advance of and during Phase II modeling with the aim of ensuring communications on key Phase II topics.

Tri-State maintains ongoing collaboration with interested stakeholders related to its next ERP, and in discussion of organized market-related matters.

Bid Evaluation

Tri-State's Phase II Request for Proposals (RFP) was issued on May 18, 2022. Tri-State's bid evaluation process was undertaken over a 30-day period following the close of the RFP on September 16, 2022. The bid evaluation process, completed prior to advancing projects to Phase II computer-based modeling, consisted of several steps – including a completeness screen, an economic screen, an interconnection/transmission screen, and a non-price factor screen.

The ***completeness review*** included an assessment of whether bids provided required information, had incomplete or missing bid forms or narratives, or did not include a redlined Form PPA. When bid information appeared incomplete or unclear, Tri-State contacted the bidders and provided them approximately two business days to supplement their bids with the necessary information for those bids to move forward in the bid evaluation process.

Following the completeness review, bids were sorted by technology type (wind, solar, etc.) and passed through an ***economic screen***. Either a levelized cost of energy (LCoE) or leveled cost of capacity (LCoC) was evaluated, depending on the technology type, as identified in the table below.

Table 1: Economic Screen by Technology Group Applied to Phase II Bids

LCoE	LCoC
Solar Wind	Standalone Battery Dispatchable Renewables[33]

[27] Excerpt from March 2, 2022 Consensus Response (filed in Proceeding 20A-0528E): "If the extreme weather sensitivities for certain portfolios evaluate poorly under this analysis, Tri-State intends to work with the parties to determine whether and to what extent it would be appropriate to make revisions to those portfolios…If the extreme weather sensitivity for any of Tri-State's portfolios fails to satisfy the minimum reliability criteria that Tri-State sets in EnCompass, Tri-State will…notify the parties as soon as practicable…"
[28] Settlement Agreement section 3.14.1.
[29] See FN 27.
[30] See FN 27.
[31] See FN 27.
[32] See FN 27.
[33] E.g., biogas, geothermal.

Wind Repowering Solar + Battery Wind + Battery	

Bids in each technology group, in various size ranges, were advanced to the transmission and interconnection screen if the costs were at or below the latest generic resource pricing (see Table 2 below) and/or where other size, locational, or diversity considerations were applied.

The ***interconnection/transmission screen*** included a review of project/facility sizes (capacity), point of interconnection (POI), transmission provider, and queue status, if applicable. Tri-State's Transmission Planning team reviewed each bid's viability and the reasonableness of associated cost estimates. The viability screen focused on the ability of the transmission system to accommodate the new firm resource and the ability to construct the project, including network upgrades and interconnection facilities by the identified in-service date. Cost estimates were reviewed to ensure bids factored in a reasonable level of network upgrade and interconnection facility costs to integrate the project at the identified point of interconnection. Finally, Tri-State's Transmission Planning team verified whether the project was in an interconnection queue based on the information provided by the bidder. This was a verification step and not one used for evaluation.

Projects not receiving favorable evaluation results during the interconnection/transmission screen were eliminated from further consideration in the bid evaluation process. In cases where the interconnection/transmission screen identified certain flawed aspects of an otherwise viable bid, related primarily to cost and/or in service date assumptions, Tri-State contacted bidders for clarification and cost updates.

Lastly, Tri-State conducted a ***non-price factor analysis*** of the bids that emerged from the interconnection and transmission screen. The non-price factor analysis considered project capabilities across four categories: community stewardship, counterparty profile, project feasibility, and project capability. The factors are identified in the table below.

Table 2: Non-Price Factors

Category	Factor
Community Stewardship	• Best Value Employment Metrics • Contribution to meeting GHG reductions in Colorado • Location in a Tri-State Member System • Land use considerations • Bids in Moffat or Montrose Counties
Counterparty Profile	• Bidder's prior experience with project development • Financial viability of the bidder • Markup of PPA terms and conditions
Project Feasibility	• Certainty of outside funding sources • Compliance with all applicable local, state and federal laws, rules and orders • Ability to source materials • Project retirement/decommissioning plan
Project Capability	• Forecasting capability

	• Renewal and purchase options at end of PPA • Impact on scheduling to load

Projects with overall favorable non-price factor analysis were advanced to modeling; however, poor evaluation results in certain non-price factor categories resulted in a project not being advanced to modeling.

Bids Received

Tri-State received 274 individual eligible bid proposals by the bid deadline, as identified in the 30-Day Report filed in Proceeding No. 20A-0528E on October 17, 2022. On October 28, 2022, Tri-State provided, via email, to Commission Staff and UCA a highly confidential list of bids advanced to modeling.[34] A total of 11 bids were advanced to modeling following the bid evaluation described above. On October 31, 2022, Tri-State notified bidders whether their projects had advanced to modeling. For bids not advanced to computer-based modeling, and for which bidders requested additional feedback on their bids, Tri-State identified at which stage of the bid evaluation process the bid failed to pass a screen and offered an opportunity for further discussion at or near the conclusion of Phase II.

Table 3: Summary of Bids Advanced to Modeling by Technology Type

Technology Type	Total (# of Bids)	MW	MW BESS	MWh BESS
Solar	5	630		
Wind	2	[redacted]		
Solar + Battery	3	430	170	680
Standalone Battery	1		200	442

Commission Rule 3605(h)(I)(A)(iii) requires that Tri-State "provide the Commission with the best value employment metrics information provided by bidders." The best value employment metrics (BVEM) information provided by bidders whose bids were advanced to modeling is provided in Attachment F. As identified in Table 2 above, BVEM is a non-price factor analyzed by Tri-State as an element of bids' community stewardship.

Settlement Agreement sections 3.9.7. and 3.12.9. require that bids in the West End of Montrose County be identified and clearly described; however, no bids in the West End of Montrose County were received. Of note, [redacted]

Tri-State is also providing to the Commission and stakeholders a mapping of the bid project locations overlayed with a map of disproportionately impacted communities, in **Highly Confidential Attachment G**.[35] The file contains three maps—one of all bids, one of bids advanced to modeling, and one of the bids selected in portfolio modeling.

Bids Selected in Portfolio Modeling

Table 4 identifies the bids selected in one or more of the portfolios modeled.

[34] Upon completion of Phase II, Tri-State will file a proposal that addresses the public release of all confidential and highly confidential information related to bids for potential resources and will post on its website certain required information from all bids and utility proposals, as required by Commission Rule 3605(h)(III).
[35] Settlement Agreement section 3.9.4.

Table 4: Bids Selected in Portfolio Modeling

Bid	Technology Type	MW	Portfolios[36]
WI-028-1-WYO-WNE	Wind	200	1, 2, 5
PV-030-1-ECO	Solar	200	2
WI-071-1-WYO-WNE	Wind	116	4
PC-PV-030-1-ECO	Solar	200	5
PC-ST-030-1-ECO	Battery	50	5

Phase II Portfolio Analysis

Tri-State modeled five portfolios, as identified in Section 3.7 of the Settlement Agreement and Attachment B-3:[37]

1. Revised Preferred Plan (RevPP)
2. Early GHG Reduction Portfolio (EGHG)
3. Reduced Load Portfolio (RL)
4. Wind Back-Up Bid Portfolio (Wind BKUP)
5. Craig 3 Early Retirement Portfolio (EC3)

The modeling assumptions unique to each portfolio are identified in Attachment B-3.

Additionally, two sensitivity analyses were performed on each portfolio's expansion plan to re-dispatch the plans under extreme weather event (EWE) and high gas (HG) price conditions. The modeling assumptions and results of the sensitivity analyses are provided in Attachment E.

Each section that follows presents data and analytical results from portfolio modeling, formatted in the following order:

- Expansion Plan, Retirements, System Mix, and Capacity Factors
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

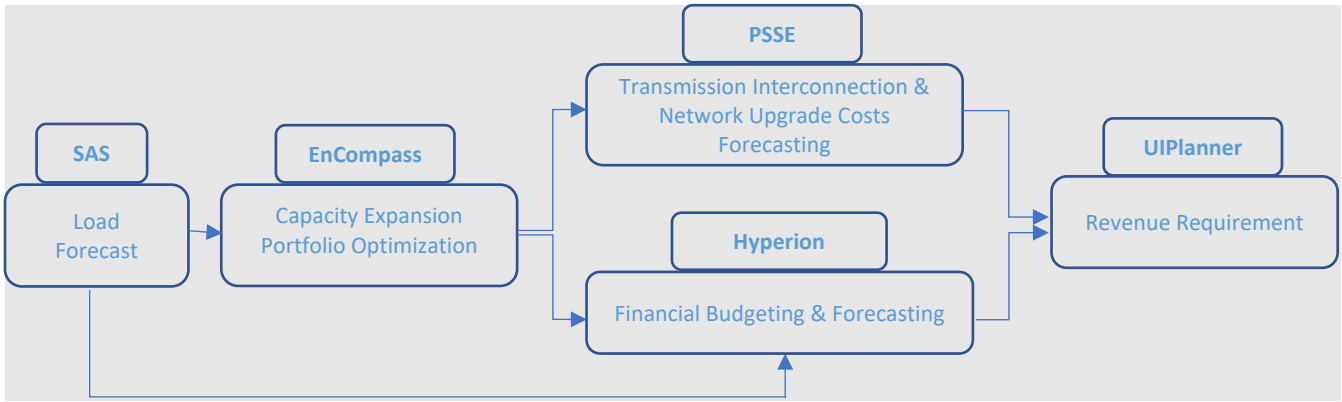
An overview of Tri-State's approach to each section of the portfolio analyses is provided below.

[36] All project bids selected in portfolio modeling had late 2025 or early 2026 commercial operation dates, resulting in the resources being "2026 resources" in alignment with section 3.4.4.1. of the Settlement Agreement, which states: "A "2026 Bid" is a bid that first contributes to capacity needs in July 2026 and is expected to be online for the majority of 2026 in order to significantly contribute to carbon reduction. Tri-State acknowledges that 2026 Bids include resources with commercial operations dates in December 2025."

[37] No unique assumptions for the Least-Cost Portfolio were identified in section 3.7.1.2. of the Settlement Agreement. Tri-State identified the need for clarification on the Least-Cost Portfolio expectations in the ERP stakeholder meeting held May 24, 2022; discussion during the meeting indicated there may not be a need for a Least-Cost Portfolio. Final modeling assumptions sent to ERP stakeholders on September 14, 2022 indicated "Unique assumptions for this portfolio are unknown at this time. The need for running this portfolio is uncertain if differing assumptions from the Revised Preferred Plan cannot be identified." A Least-Cost Portfolio was not run because no differing assumptions from the Revised Preferred Plan could be identified by Tri-State.

Error! Reference source not found. below identifies the software tools utilized by Tri-State for completing each component of the portfolio analyses and the succession of data through each system.

Figure 1: Modeling Software Tools



Use of the EnCompass modeling software for capacity expansion and portfolio optimization is new for Tri-State starting in 2022. In December 2022, Anchor Power (the EnCompass software vendor), provided modeling QA/QC for one portfolio run for Tri-State's Phase II. The QA/QC process was able to effectively reproduce the same modeling results, affirming the proper set-up and operation of EnCompass for Phase II.

Expansion Plan, Retirements, System Mix, and Capacity Factors

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase II modeling, inputting the applicable modeling assumptions described in Attachment B[38] and reflecting the Tri-State system topology, provided as Attachment B-4. Resource bids advanced to modeling as a result of the Request for Proposals (RFP) issued by Tri-State on May 18, 2022 and selected in the portfolio expansion plans are identified by a bid identifier, resource type, and project megawatts (MW).

Given that Phase I of the ERP extended longer than anticipated, concluding in early 2022, the RAP and Resource Planning Period (RPP) modeled for Phase II were both shortened by one year to 2022-2030 and 2022-2040, respectively.[39]

Environmental Analyses

Based on the expansion plan and dispatch produced for each portfolio, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon and methane. SCoC values reflect the February 2021 Interagency Working Group (IWG) on Social Cost of Greenhouse Gases, Technical Support Document.[40]

[38] See Attachments B, B-1, B-2, and B-3.
[39] At the time Phase II modeling was initiated, calendar year 2022 had not concluded, therefore all 2022 data included in this report is based on short-term forecasts rather than actuals.
[40] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

For each portfolio, Tri-State separately produced a verification workbook calculating forecasted carbon emissions reductions, provided in Attachment D.[41] Target-year emissions reductions percentages for each portfolio, calculated within the verification workbooks, are provided in this report.

Although 2020 eGRID rates were available, Tri-State used 2018 EPA eGRID rates for forecasted market purchases and sales, the Basin Eastern Interconnection contract, and the Basin Electrically Western Interconnection contract. Although the grid is expected to become decarbonized over time, using 2018 eGRID rates rather than 2020 eGRID was a more conservative approach for modeling as there is ambiguity in emissions rates due to organized market formation and sourcing of Basin Western Interconnection contract. The carbon emission rate assumption for market purchases and sales and Basin Western Interconnection contract is 1,280 pounds per MWh through 2029 per 2018 eGRID rate (2020 eGRID rate is 1,144 pounds per MWh) and 450 pounds per MWh, per ACDP Workbook requirement, starting in 2030. The carbon emission rate assumption for Basin Eastern Interconnection contract is 1,240 pounds per MWh through 2029, which is the 2018 eGRID rate (2020 eGRID rate is 980 pounds per MWh) and 675 pounds per MWh, per APCD Workbook requirement starting in 2030. Tri-State reviewed this conservative approach to the market emission rates with stakeholders during a meeting held January 19, 2023.

Financial Analyses

Pursuant to Rule 3605(h)(I)(A)(ii), Tri-State provided a financial analysis of each portfolio and each Tri-State owned resource, including:

- Annual revenue requirements;
- Present value revenue requirement, with and without the social costs of carbon and methane; and
- A net present value of each owned resource, over the planning period, with and without the social costs of carbon and methane.

Additionally, one of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order.[42] For each portfolio, curtailment MWhs by intermittent resource type seasonally and year are provided.

Transmission Analyses

Each portfolio was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades. Transmission facilities included in Tri-State's application to the CoPUC for certificates of public convenience and necessity" (CPCNs) for eastern Colorado transmission upgrades[43] were treated as "planned upgrades not yet in service" as of their anticipated installation dates for purposes of

[41] The emissions baseline in the verification workbooks differs slightly from Phase I of the ERP, reflecting the removal of load associated with Tri-State Members who have opted for Partial Requirements – MAX contracts. This adjustment aligns with Section 3.6.4. of the Settlement Agreement.

[42] In the event that resources must be curtailed, Tri-State's model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic min and must take contracts (i.e., hydropower and Basin contracts)–in that order.

[43] Filed February 18, 2022 in Proceeding No. 22A-0085E.

the analyses and, therefore, are not included in the values shown for "Expansion Plan CapEx + IDC: Transmission" but are included in the PVRR and annual revenue requirements.

Bidder-provided transmission cost estimates for proposed generation projects submitted in response to Tri-State's RFP were analyzed as part of the bid evaluation process to identify bids that should be advanced to portfolio modeling. Any project bids received by Tri-State in response to the RFP that intend to interconnect to transmission facilities included in Tri-State's application for CPCNs, but with in-service dates prior to the proposed CPCN project in-service dates, were required to factor that into their bids.[44]

Reliability Analyses

Level 1 reliability metric checks were performed on each portfolio, including:

- *Planning Reserve Margin (PRM):* Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%).
    - Target (min) is 15%
- *Loss of Load Hours (LoLH)*[45]: Measure of the likelihood of failing to meet system load (hours per 10 years).
    - Target (max) is 1 day in 10 years (99.973% reliability)
        - 2022-2030 – annually cannot exceed 2.4 hours
        - 2031-2040 – cannot exceed 24 hours over entire period
- *Expected Unserved Energy (EUE)*[46]: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
    - Targets (max):
        - ≤ 0.5 GWh annually

A detailed analysis of how load will be served from intermittent resources is also provided for portfolios that retired a dispatchable resource.

[44] Bidders can request in-service dates be accelerated under LGIP or LGIA procedures.
[45] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2020 ERP Phase I.
[46] EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.

1. Revised Preferred Plan

The Revised Preferred Plan portfolio and assumptions served as the base case portfolio for Phase II.[47] Assumptions unique to the Revised Preferred Plan portfolio are identified in Attachment B-3.

Portfolio 1 (Revised Preferred Plan) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 5: Expansion Plan (Revised Preferred Plan Portfolio)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026	Wind (WI-028-1-wyo-wne)	Wyoming/Nebraska	200	1	200
2028	Wind (Build Transfer)	Wyoming/Nebraska	100	2	200
2029	Wind (Build Transfer)	East Colorado	100	3	300
2030	Solar	East Colorado	100	1	100
	Solar	West Colorado	100	4	400
	4 hr - Battery	West Colorado	100	1	100
	4 hr - Battery	West Colorado	25	1	25
	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
	Gas Combustion Turbine	West Colorado	193	1	193
2031	4 hr - Battery	New Mexico	100	1	100
	4 hr - Battery	West Colorado	100	1	100
2032	Wind (Build Transfer)	New Mexico	100	1	100
	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
	Wind	East Colorado	100	2	200
2033	Wind	East Colorado	100	8	800
	Wind	New Mexico	100	2	200
2034	4 hr - Battery	East Colorado	100	1	100
	Wind	East Colorado	100	1	100
2038	Solar	West Colorado	100	1	100
2039	4 hr - Battery	East Colorado	100	1	100
2040	Solar	West Colorado	100	5	500
	4 hr - Battery	West Colorado	100	1	100

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- No additional EE was selected in the expansion plan of the Revised Preferred Plan.

[47] Paragraph 78 of Decision No. R22-0191: "…Tri-State shall continue to present a base case portfolio consistent with its ERP, including base assumptions as updated by the Settlement Agreement."

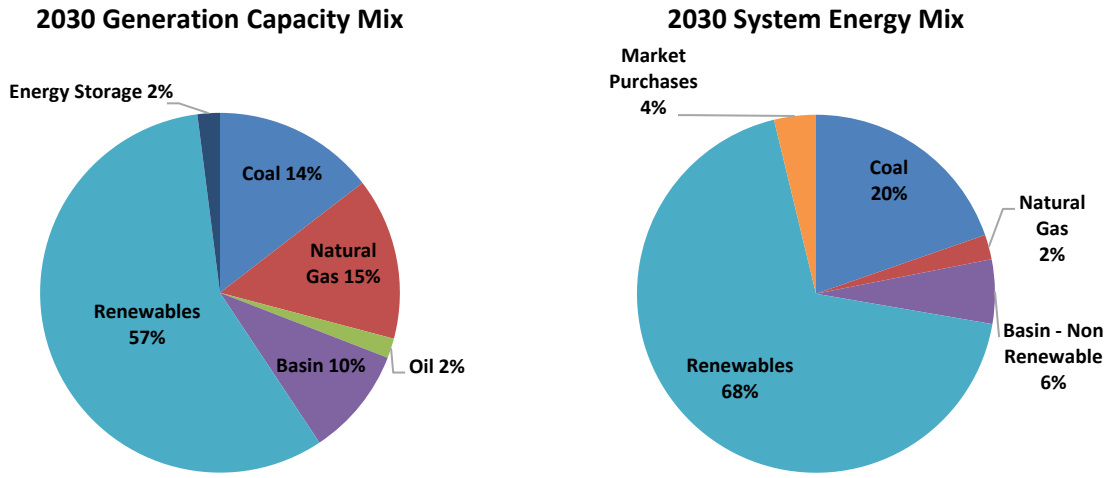
Unit retirements selected in the modeling are shown in the following table.[48]

Table 6: Modeled Retirements (Revised Preferred Plan Portfolio)

Location	MW	Technology	Date
Craig 3	448	Coal	12/31/2029
Springerville 3	419	Coal	1/1/2040[49]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 2: Projected Tri-State System Resource Mix 2030 (Revised Preferred Plan Portfolio)[50, 51]



[48] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.

[49] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.

[50] "Renewables" category reflects wind and solar PPAs, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.

[51] System Energy Mix reflects sales to Members and non-Members.

Table 7: Projected Annual Capacity Factors for Thermal Resources (Revised Preferred Plan Portfolio)

Thermal Resource	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	73%	80%	77%	50%	-	-	-	-	-
Craig 2	86%	84%	93%	32%	31%	7%	7%	-	-
Craig 3	73%	90%	79%	66%	63%	44%	31%	22%	-
LRS 2	51%	81%	70%	83%	70%	80%	79%	78%	63%
LRS 3	54%	70%	62%	47%	61%	51%	47%	39%	56%
SPV 3	72%	60%	56%	69%	71%	69%	62%	61%	54%
JM Shafer	16%	5%	5%	22%	19%	45%	38%	27%	12%
Rifle	2%	-	-	-	-	-	-	-	-
Limon	2%	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%	0%
Pyramid	8%	10%	1%	13%	8%	9%	8%	7%	3%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%
193 MW CT West Colorado	-	-	-	-	-	-	-	-	8%

Portfolio 1 (Revised Preferred Plan) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

Table 8: Environmental Impact - System Wide (Revised Preferred Plan Portfolio)[52]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2022[53]	12,983,932	6,292	10,182	0.2230	409	5,220,513,340	29,493
2023	13,236,948	6,666	10,987	0.2547	429	5,396,587,708	30,624
2024[54]	12,080,369	6,028	9,842	0.2264	379	4,903,055,968	28,125
2025	11,391,567	5,617	9,142	0.2006	358	4,656,896,322	25,697
2026	10,800,773	5,607	8,388	0.1942	353	4,408,782,191	24,392
2027	10,170,496	5,042	7,774	0.1601	338	4,119,039,328	21,828
2028	9,216,480	4,537	6,947	0.1336	300	3,600,196,358	19,369
2029	8,372,919	4,107	6,171	0.1126	259	3,183,889,130	17,576
2030	5,998,477	3,599	5,041	0.0764	231	2,510,012,063	14,683
2031	5,804,891	3,646	5,167	0.0771	227	2,372,970,720	14,219
2032	4,844,978	3,137	4,359	0.0638	181	1,944,541,883	12,237
2033	3,236,139	2,163	2,772	0.0349	93	1,229,265,966	8,522
2034	3,250,950	2,205	2,872	0.0369	101	1,229,302,841	8,449

[52] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[53] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.

[54] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2035	3,420,743	2,270	2,932	0.0378	101	1,310,661,128	8,932
2036	3,179,535	2,257	3,028	0.0376	107	1,148,852,072	8,181
2037	2,783,449	2,235	3,246	0.0393	121	894,190,119	6,643
2038	2,617,181	2,137	3,083	0.0354	110	808,747,853	6,233
2039	2,719,064	2,215	3,200	0.0374	115	844,733,917	6,487
2040	2,976,408	2,385	3,487	0.0412	128	940,034,205	7,067
Total	**129,085,300**	**72,147**	**108,622**	**2.023**	**4,340**	**50,722,273,115**	**298,757**
Pounds/Gallons per MWh[55]	**829**	**0.46**	**0.70**	**0.00001**	**0.03**	**163**	**2.11**

Table 9: Social Cost of Carbon Nominal Dollars – System Wide (Revised Preferred Plan Portfolio)

Year	Annual Social Cost of Carbon
2022	$1,038,911,749
2023	$1,106,805,608
2024	$1,051,155,113
2025	$1,029,231,387
2026	$1,013,023,741
2027	$988,068,664
2028	$927,233,404
2029	$872,130,962
2030	$646,742,348
2031	$648,111,840
2032	$560,035,451
2033	$387,189,697
2034	$402,524,463
2035	$438,221,341
2036	$421,347,919
2037	$381,487,319
2038	$370,913,081
2039	$398,395,931
2040	$450,782,578

[55] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 10: Social Cost of Methane Nominal Dollars – System Wide (Revised Preferred Plan Portfolio)

Year	Annual Social Cost of Methane
2022	$67,938,645
2023	$74,466,457
2024	$71,863,757
2025	$68,813,076
2026	$68,416,552
2027	$63,962,740
2028	$59,264,169
2029	$56,122,398
2030	$48,901,831
2031	$49,537,142
2032	$44,563,390
2033	$32,422,468
2034	$33,565,315
2035	$37,031,220
2036	$35,376,889
2037	$29,949,676
2038	$29,279,882
2039	$31,743,858
2040	$36,003,537

Table 11: GHG Emissions Reduction Percentages, Targets and Forecast (Revised Preferred Plan Portfolio)

Year	Target[56]	Forecast
2025	26%	33%
2026	36%	43%
2027	46%	49%
2030	80%	81%

See Appendix D for detailed GHG emissions calculations for the portfolio.

Portfolio 1 (Revised Preferred Plan) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), annual revenue requirement, and NPV by resource for the portfolio are shown below.

[56] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.

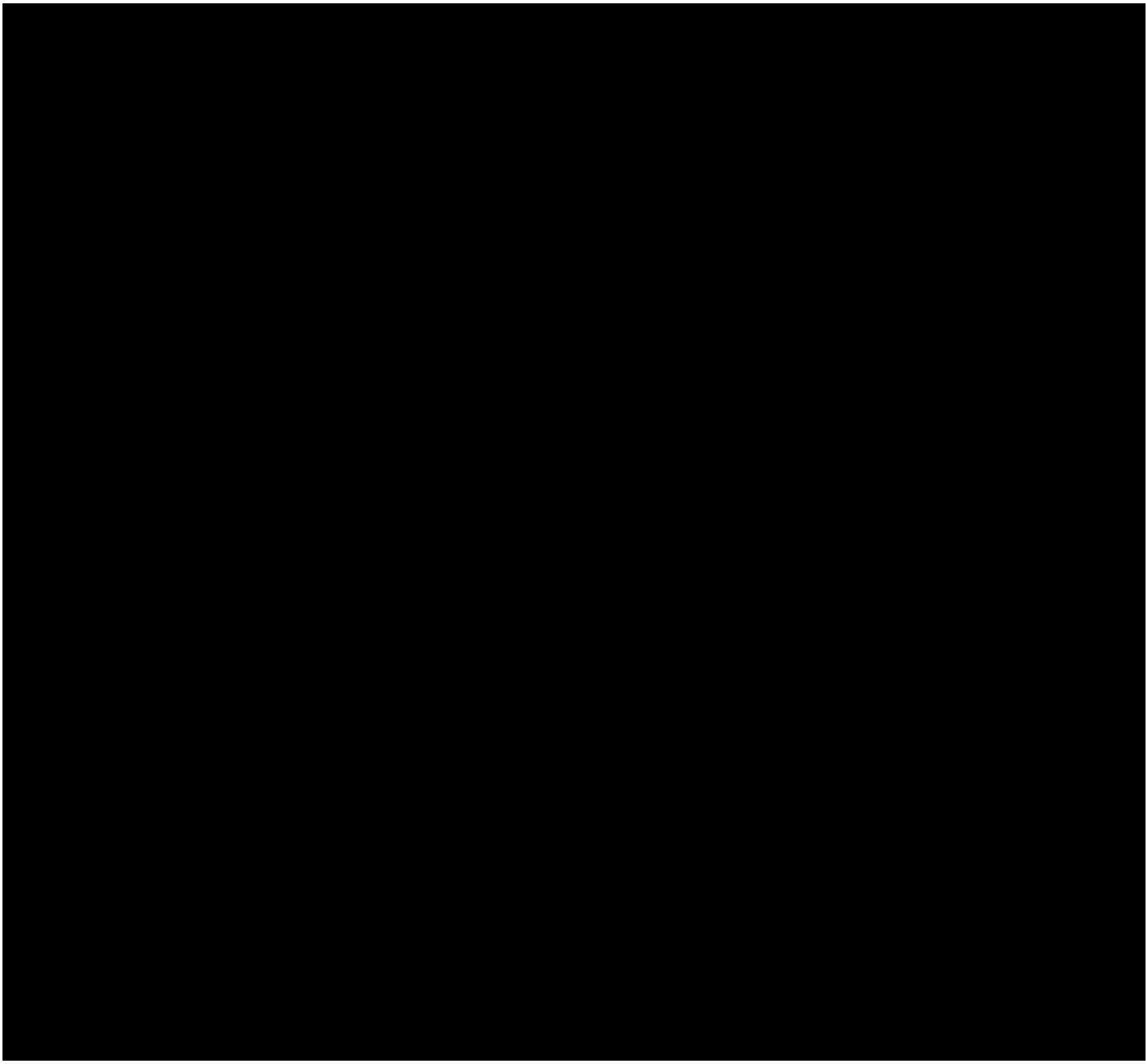
Table 12: Total Financial (Revised Preferred Plan Portfolio)

$, Millions	**Portfolio PVRR** (2022 WACC 4.18%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$18,465.6	$10,888.9	$771.0	$29,354.5	$30,125.5
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,481.5				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$1,761.8				

Table 13: Annual Financial (Nominal $) (Revised Preferred Plan Portfolio)

Year	**Total Annual Revenue Requirement ($, Millions)**
2022	$1,176
2023	$1,171
2024	$1,137
2025	$1,114
2026	$1,195
2027	$1,264
2028	$1,345
2029	$1,398
2030	$1,479
2031	$1,569
2032	$1,578
2033	$1,604
2034	$1,624
2035	$1,638
2036	$1,648
2037	$1,652
2038	$1,671
2039	$1,707
2040	$1,725

Table 14: NPV by Resource (Revised Preferred Plan Portfolio)[57, 58]



[57] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[58] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[59] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[60] NPV using 2.5% discount rate
[61] NPV using 2.5% discount rate

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the Revised Preferred Plan Portfolio dispatch, through 2029. In 2030, with the addition of 600 MW of intermittent resources, 125 MW of batteries, and the retirement of Craig 3, we begin to see more substantial curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Since solar resources do not typically have a production tax credit (PTC) penalty associated with curtailment, they are curtailed first. Total financial curtailment costs in 2030 exceed $4.5 million, as shown in Table 17 below, and reflect 90% of the curtailment costs over the RAP.

Table 15: Curtailed Intermittent Energy, Annual MWh (Revised Preferred Plan Portfolio)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Bid Wind	Bid Solar	Total
2022	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	**0**
2025	0	472	0	0	0	0	**472**
2026	0	1,086	0	0	0	0	**1,086**
2027	0	2,356	0	0	0	0	**2,356**
2028	75	2,914	6	0	3	0	**2,998**
2029	1,112	10,203	13	0	9	0	**11,338**
2030	31,183	38,850	10,065	91,325	3,108	0	**174,530**
RAP Total	**32,369**	**55,882**	**10,084**	**91,325**	**3,120**	**0**	**192,780**

Table 16: Seasonal Intermittent Resource Curtailments, Annual MWh (Revised Preferred Plan Portfolio)

	Winter	Spring	Summer	Fall
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	44	416	0	12
2026	284	756	0	46
2027	126	2,146	0	84
2028	286	2,692	19	0
2029	136	10,605	29	567
2030	17,435	130,461	8,916	17,717
RAP Total	**18,311**	**147,077**	**8,965**	**18,426**

The following table reflects PPA pricing, penalties, and taxes.

Table 17: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (Revised Preferred Plan Portfolio)

	Wind ($)	Solar ($)
2022	$0	$0
2023	$0	$0
2024	$0	$0
2025	$0	$11,490
2026	$0	$26,572
2027	$0	$64,948
2028	$3,348	$75,517
2029	$46,512	$234,197
2030	$1,727,512	$2,933,914
RAP Total	**$1,777,373**	**$3,346,638**

Portfolio 1 (Revised Preferred Plan) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[62]

Table 18: Transmission Interconnection & Network Upgrade Expenses Real (2022) $ (Revised Preferred Plan Portfolio)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind (Build Transfer)		$2.21	
2029	100	Wind (Build Transfer)		$2.21	
2029	100	Wind (Build Transfer)		$2.21	
2030	100	Solar		$2.21	
2032	100	Wind		$7.30	
2032	100	Wind		$2.21	
2033	100	Wind		$2.21	
2033	100	Wind		$2.21	
2033	100	Wind		$3.11	$836.22
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	

[62] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind		$3.11	
2034	100	Battery	$1.30	$2.21	
2034	100	Wind		$3.11	
2039	100	Battery	$1.30	$2.21	
Western Colorado (WCO) Transmission Area					
2030	193	Gas	$1.40	$3.11	
2030	25	Battery	$1.30	$2.21	
2030	100	Battery	$1.30	$2.21	
2030	100	Solar		$2.21	
2030	100	Solar		$3.11	
2030	100	Solar		$3.11	
2030	100	Solar		$3.11	
2031	100	Battery	$1.20	$1.22	
2038	100	Solar		$1.22	
2040	100	Battery	$1.40	$3.11	
2040	100	Solar		$3.11	
2040	100	Solar		$1.22	
2040	100	Solar		$9.98	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
Wyoming (WYO) Transmission Area					
2026	200	Wind		$3.11	
2028	100	Wind (Build Transfer)		$3.11	$92.61
2028	100	Wind (Build Transfer)		$3.11	
2030	100	Wind (Build Transfer)		$3.11	
2032	100	Wind (Build Transfer)		$3.11	$26.00
New Mexico (NM) Transmission Area)					
2031	100	Battery	$1.30	$2.21	
2032	100	Wind (Build Transfer)		$2.21	$221.98
2033	100	Wind		$2.21	
2033	100	Wind		$2.21	

Portfolio 1 (Revised Preferred Plan) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. An analysis of the ability to serve load when Craig 3 is not available is also provided.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 1 Revised Preferred Plan.

Table 19: Planning Reserve Margin, % Annual (Revised Preferred Plan Portfolio)

2022	2023	2024	2025	2026	2027	2028	2029	2030
17	22	25	39	36	33	33	30	29

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 1 Revised Preferred Plan.

Table 20: Loss of Load Probability, Hours (Revised Preferred Plan Portfolio)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 1 Revised Preferred Plan.

Table 21: Expected Unserved Energy, Annual MWh (Revised Preferred Plan Portfolio)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Ability to Serve Load When Craig 3 Offline

In this portfolio analysis, Craig 3 retires December 31, 2029. To meet reliability metrics (see page 17) starting in 2030, the PRM is increased to 20%. The model selects the following semi-dispatchable and dispatchable resources in 2030: 125 MW of batteries in WCO and a 193 MW CT Gas unit in WCO. Reliability is met from 2031-2040 with the following battery storage additions: 100 MW in NM, 200 MW in ECO, and 200 MW in WCO.

Dispatchable Retirements

Section 3.10.3. of the Settlement Agreement requires a detailed analysis of how load will be served from intermittent resources and Tri-State's other system resources under different service conditions (such as extreme weather events) for any portfolio that includes the retirement of dispatchable resources.

For the Revised Preferred Plan portfolio, dispatchable resource retirements selected by the model include the Craig units (on the previously announced dates) and Springerville 3 in 2040. In the period from 2025-2029 when Craig Units 1 and 2 retire, Tri-State continues to be capacity-long and maintains a sufficient mix of both dispatchable and intermittent resources to meet load needs. During that period, Craig 3, LRS 2 & 3, and SPV 3 continue to contribute significantly to meeting capacity needs. In the section above, Tri-State addressed the mix of new intermittent and dispatchable resources modeled to come online to serve load during the period following the Craig 3 retirement. With the modeled early retirement of SPV 3 coming at the end of the resource planning period, LRS units, existing gas resources

including JM Shafer, and the new gas CT will all continue to be available to meet capacity needs, along with the battery additions modeled to occur in 2040 and in years prior. Additionally, Tri-State expects to move a portion, if not all, of its system into a regional transmission organization (RTO) no later than 2030[63]. While this does not replace the need for Tri-State to acquire and build sufficient capacity to meet resource adequacy and reliability, entry into an organized market does allow for diversity of resources across a wider footprint which provides for market operator flexibility in meeting changing system conditions.

[63] Tri-State has provided more detailed information on its planned transition to organized markets in Proceeding No. 22R-0249E.

2. Early GHG Reduction Portfolio

Portfolio 2 (EGHG) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 22: Expansion Plan (EGHG)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026[64]	Solar (PV-030-1-eco)	East Colorado	200	1	200
2026	Wind (WI-028-1-wyo-wne)	Wyoming/Nebraska	200	1	200
2027	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
2028	Wind (Build Transfer)	Wyoming/Nebraska	100	2	200
2029	Solar	West Colorado	100	2	200
	4 hr – Battery	West Colorado	100	1	100
	4 hr – Battery	West Colorado	25	1	25
	Wind (Build Transfer)	East Colorado	100	3	300
2030	Solar	West Colorado	100	1	100
	Gas Combustion Turbine	West Colorado	193	1	193
2031	4 hr – Battery	New Mexico	100	1	100
	4 hr – Battery	West Colorado	100	1	100
2032	Wind (Build Transfer)	New Mexico	100	2	200
	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
	Wind	East Colorado	100	2	200
2033	Wind	East Colorado	100	9	900
	Wind	New Mexico	100	1	100
2034	4 hr – Battery	East Colorado	100	1	100
2040	Solar	West Colorado	100	5	500
	4 hr – Battery	East Colorado	100	2	200
	4 hr – Battery	West Colorado	100	1	100

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- No additional EE was selected in the expansion plan of the EGHG portfolio.

[64] This bid has an in-service date in late 2025 (in-service dates are provided in HIGHLY CONFIDENTIAL Attachment C); section 3.4.4.1. of the Settlement Agreement states that a "2026 Bid" is a bid that first contributes to capacity needs in July 2026 and is expected to be online for the majority of 2026 in order to significantly contribute to carbon reduction.

Unit retirements selected in the modeling are shown in the following table.[65]

Table 23: Modeled Retirements (EGHG)

Location	MW	Technology	Date
Craig 3	448	Coal	12/31/2029
Springerville 3	419	Coal	1/1/2040[66]
Burlington 2	48[67]	Fuel Oil	1/1/2040[68]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 3: Projected Tri-State System Resource Mix 2030 (EGHG)[69, 70]

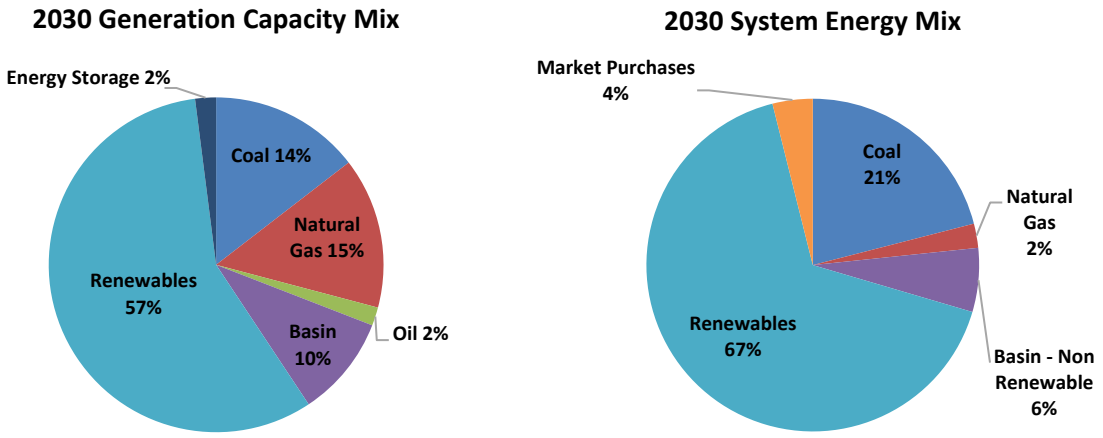


Table 24: Projected Annual Capacity Factors for Thermal Resources (EGHG)

Thermal Resource	2022	2023	2024[71]	2025	2026	2027	2028	2029	2030
Craig 1	73%	80%	29%	27%	-	-	-	-	-
Craig 2	86%	84%	16%	13%	15%	4%	2%	-	-
Craig 3	73%	90%	62%	57%	51%	33%	19%	2%	-
LRS 2	51%	81%	60%	81%	68%	79%	76%	71%	63%

[65] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.
[66] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.
[67] 48 MW is the summer capacity rating for Burlington; and 60 MW is the winter capacity rating for Burlington.
[68] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire Burlington 2 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its plants.
[69] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[70] System Energy Mix reflects sales to Members and non-Members.
[71] Redispatching of thermal resources occurs in 2024 to meet early GHG targets which results in higher gas capacity factors and lower coal capacity factors, for some units.

LRS 3	54%	70%	8%	44%	58%	45%	41%	33%	55%
SPV 3	72%	60%	75%	68%	70%	68%	60%	59%	53%
JM Shafer	16%	5%	47%	38%	24%	41%	35%	27%	11%
Rifle	2%	-	-	-	-	-	-	-	-
Limon	2%	1%	1%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%	0%
Pyramid	8%	10%	24%	16%	9%	10%	10%	10%	3%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%
193 MW CT West Colorado	-	-	-	-	-	-	-	-	8%

Portfolio 2 (EGHG) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

Table 25: Environmental Impact - System Wide (EGHG)[72]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2022[73]	12,983,932	6,292	10,182	0.2230	409	5,220,513,340	29,493
2023	13,236,796	6,666	10,988	0.2547	429	5,397,427,780	30,623
2024[74]	10,279,291	4,645	7,683	0.1624	276	4,100,458,794	21,842
2025	10,723,153	5,255	8,472	0.1804	346	4,387,317,606	23,539
2026	10,052,408	5,177	7,717	0.1696	331	4,061,036,383	22,337
2027	9,372,178	4,584	7,015	0.1368	306	3,753,733,846	19,966
2028	8,364,046	4,043	6,139	0.1085	266	3,201,532,832	17,344
2029	7,124,089	3,352	4,940	0.0734	214	2,622,205,161	14,402
2030	5,980,029	3,586	5,025	0.0763	230	2,502,305,821	14,651
2031	5,793,816	3,645	5,153	0.0772	227	2,368,560,718	14,207
2032	4,659,379	3,025	4,184	0.0609	171	1,865,195,711	11,840
2033	3,090,588	2,074	2,622	0.0321	85	1,164,085,516	8,170
2034	3,226,343	2,191	2,849	0.0365	99	1,218,121,332	8,394
2035	3,398,074	2,256	2,911	0.0375	100	1,301,031,286	8,880
2036	3,175,388	2,256	3,026	0.0376	107	1,147,763,669	8,175
2037	2,776,086	2,229	3,238	0.0392	121	892,208,996	6,629
2038	2,679,619	2,175	3,152	0.0364	113	834,043,345	6,380
2039	2,714,332	2,217	3,202	0.0369	113	834,920,669	6,489
2040	3,072,119	2,450	3,593	0.0431	132	978,026,373	7,299

[72] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO2, SO2 and NOx are per net MWh; HG and particulate matter (PM) are per gross MWh.
[73] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[74] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.

Total	**122,701,666**	**68,117**	**102,090**	**1.822**	**4,076**	**47,850,489,178**	**280,663**
Pounds/Gallons per MWh[75]	**788**	**0.44**	**0.66**	**0.00001**	**0.03**	**154**	**1.99**

Table 26: Social Cost of Carbon Nominal Dollars – System Wide (EGHG)

Year	Annual Social Cost of Carbon
2022	$1,038,911,749
2023	$1,106,792,852
2024	$894,437,039
2025	$968,839,997
2026	$942,833,247
2027	$910,511,639
2028	$841,473,441
2029	$742,051,590
2030	$644,753,394
2031	$646,875,423
2032	$538,581,904
2033	$369,775,162
2034	$399,477,693
2035	$435,317,328
2036	$420,798,368
2037	$380,478,089
2038	$379,761,900
2039	$397,702,562
2040	$465,278,167

[75] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 27: Social Cost of Methane Nominal Dollars – System Wide (EGHG)

Year	Annual Social Cost of Methane
2022	$67,938,645
2023	$74,463,270
2024	$55,808,422
2025	$63,036,195
2026	$62,653,055
2027	$58,508,215
2028	$53,066,829
2029	$45,988,403
2030	$48,797,547
2031	$49,493,536
2032	$43,119,191
2033	$31,084,266
2034	$33,344,708
2035	$36,816,129
2036	$35,352,502
2037	$29,886,926
2038	$29,973,889
2039	$31,753,639
2040	$37,186,436

Table 28: GHG Emissions Reduction Percentages, Targets and Forecast (EGHG)

Year[76]	Target[77]	Early GHG Targets[78]	Forecast
2024	N/A	26%	26%
2025	26%	36%	41%
2026	36%	46%	52%
2027	46%	N/A	61%
2029	N/A	80%	85%

See Appendix D for detailed GHG emissions calculations for the portfolio through 2030. For this portfolio, Tri-State completed an additional annual emissions calculation (for 2024), given the portfolio parameters—to advance the emission reduction targets by one year, to achieve at least a 26% reduction in 2024.

Portfolio 2 (EGHG) – Financial Analysis

The PVRR, NPV of the SCoC and SCoM, total CapEx and IDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

[76] The carbon emission rate assumption for market purchases and sales is 1,280 pounds per MWh through 2029 and 450 pounds per MWh starting in 2030.
[77] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.
[78] GHG targets were modeled as accelerated for this portfolio from the years 2025, 2026, 2027 and 2030 to the years 2024, 2025, 2026, and 2029, per the Settlement Agreement.

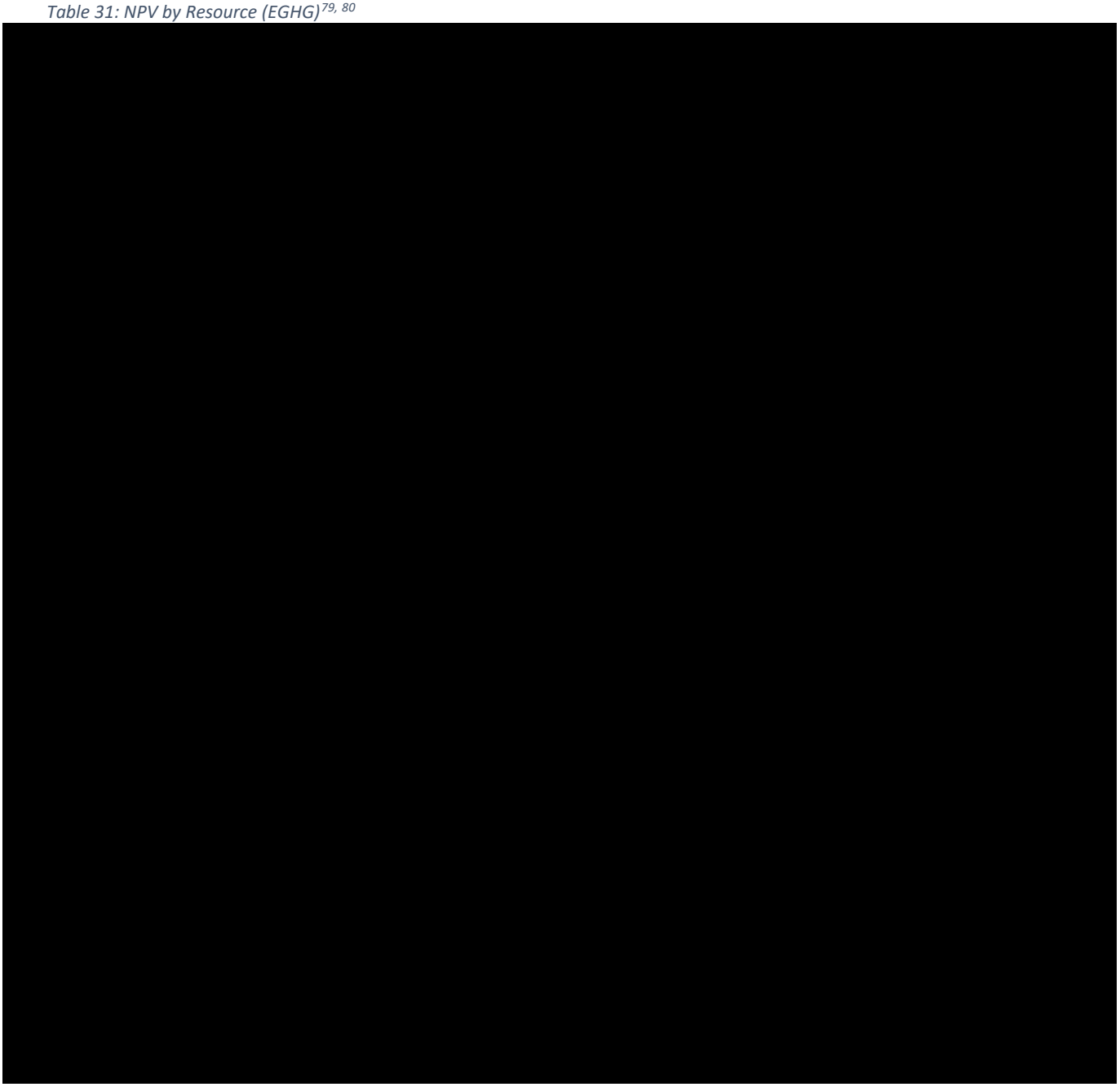
Table 29: Total Financial (EGHG)

$, Millions	**Portfolio PVRR** (2022 WACC 4.18%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$18,576.8	$10,358.1	$726.1	$28,934.9	$29,661.0
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,681.5				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$1,757.0				

Table 30: Annual Financial (Nominal $) (EGHG)

Year	**Total Annual Revenue Requirement ($, Millions)**
2022	$1,176
2023	$1,171
2024	$1,194
2025	$1,172
2026	$1,200
2027	$1,219
2028	$1,379
2029	$1,373
2030	$1,482
2031	$1,597
2032	$1,577
2033	$1,617
2034	$1,626
2035	$1,640
2036	$1,652
2037	$1,654
2038	$1,671
2039	$1,702
2040	$1,733

Table 31: NPV by Resource (EGHG)[79, 80]



[79] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[80] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[81] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[82] NPV using 2.5% discount rate
[83] NPV using 2.5% discount rate

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the Early GHG Portfolio dispatch, through 2028. In 2029, with the addition of 500 MW of intermittent resources, 125 MW of batteries, and the retirement of Craig 3 (at the end of 2029) we begin to see more substantial curtailments – primarily impacting solar and occurring in the spring season. Total financial curtailment costs for wind and solar resources in 2030 exceed $4 million, as shown in Table 34 below, and reflect 59% of the curtailment costs over the RAP.

Table 32: Curtailed Intermittent Energy, Annual MWh (EGHG)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Bid Wind	Bid Solar	Total
2022	0	0	0	0	0	0	**0**
2023	0	0	0	0	0	0	**0**
2024	0	0	0	0	0	0	**0**
2025	0	941	0	0	0	76	**1,017**
2026	0	5,455	0	0	0	2,988	**8,443**
2027	0	6,024	0	0	0	2,916	**8,941**
2028	137	11,468	3,122	0	1,050	4,460	**20,236**
2029	4,453	25,000	7,103	20,842	2,286	24,359	**84,043**
2030	16,217	38,903	9,433	56,561	3,295	49,427	**173,838**
RAP Total	**20,807**	**87,791**	**19,658**	**77,404**	**6,631**	**84,226**	**296,517**

Table 33: Seasonal Renewable Curtailments, Annual MWh (EGHG)

	Winter	Spring	Summer	Fall
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	126	742	42	107
2026	1,426	5,949	348	719
2027	275	7,591	692	382
2028	1,224	18,514	154	345
2029	1,465	75,944	2,034	4,600
2030	15,505	132,550	8,594	17,189
RAP Total	**20,020**	**241,290**	**11,865**	**23,342**

The following table reflects PPA pricing, penalties, and taxes.

Table 34: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (EGHG)

	Wind ($)	Solar ($)
2022	$0	$0
2023	$0	$0
2024	$0	$0
2025	$0	$27,779
2026	$0	$199,281
2027	$0	$213,979
2028	$148,076	$360,001
2029	$503,076	$1,595,780
2030	$1,100,907	$3,221,973
RAP Total	**$1,752,059**	**$5,618,793**

Portfolio 2 (EGHG) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[84]

Table 35: Transmission Interconnection & Network Upgrade Expenses (2022 Real $) (EGHG)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2025	200	Solar		$7.30	
2029	100	Wind (BT)		$2.21	
2029	100	Wind (BT)		$2.21	
2029	100	Wind (BT)		$2.21	
2032	100	Wind		$7.30	
2032	100	Wind		$2.21	
2033	100	Wind		$2.21	
2033	100	Wind		$2.21	
2033	100	Wind		$3.11	$836.22
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	

[84] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2034	100	Battery	$1.30	$2.21	
2040	100	Battery	$1.30	$2.21	
2040	100	Battery	$1.30	$2.21	
Western Colorado (WCO) Transmission Area					
2029	100	Solar		$2.21	
2029	100	Solar		$2.21	
2029	100	Battery	$1.30	$2.21	
2029	25	Battery	$1.30	$2.21	
2030	193	Gas	$1.40	$3.11	
2030	100	Solar		$1.22	
2031	100	Battery	$1.20	$1.22	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
2040	100	Solar		$9.98	
2040	100	Solar		$3.11	
2040	100	Battery	$1.40	$3.11	
Wyoming (WYO) Transmission Area					
2026	200	Wind		$3.11	
2028	100	Wind (BT)		$3.11	$92.61
2028	100	Wind (BT)		$3.11	
2030	100	Wind (BT)		$3.11	
2032	100	Wind (BT)		$3.11	$26.00
New Mexico (NM) Transmission Area)					
2031	100	Battery	$1.30	$2.21	
2032	100	Wind (BT)		$2.21	$221.98
2032	100	Wind		$2.21	
2033	100	Wind		$2.21	

Portfolio 2 (EGHG) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. Analyses of the ability to serve load when Craig 3 is not available and the impact of early retirement of the Burlington Unit 2 are also provided. The model did not choose to retire Burlington Unit 1 during the resource planning period.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 2 EGHG.

Table 36: Planning Reserve Margin, % Annual (EGHG)

2022	2023	2024	2025	2026	2027	2028	2029	2030
17	22	25	40	37	35	36	38	29

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 2 EGHG.

Table 37: Loss of Load Probability, Hours (EGHG)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 2 EGHG.

Table 38: Expected Unserved Energy, Annual MWh (EGHG)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Ability to Serve Load When Craig 3 Offline

In this portfolio analysis, Craig 3 retires December 31, 2029. To meet reliability metrics (see page 17) starting in 2029, the PRM is increased to 20%. The model selects the following semi-dispatchable and dispatchable resources in 2029 and 2030: 125 MW of standalone batteries in WCO and a 193 MW CT Gas unit in WCO. Reliability is met from 2031-2040 with the following battery storage additions: 100 MW in NM, 300 MW in ECO, and 200 MW in WCO.

Dispatchable Retirements

Section 3.10.3. of the Settlement Agreement requires a detailed analysis of how load will be served from intermittent resources and Tri-State's other system resources under different service conditions (such as extreme weather events) for any portfolio that includes the retirement of dispatchable resources.

For the Early GHG portfolio, dispatchable resource retirements selected by the modeling include the Craig units (on the previously announced dates) and Springerville 3 and Burlington Unit 2 in 2040. In the period from 2025-2029 when Craig Units 1 and 2 retire, Tri-State continues to be capacity-long and maintains a sufficient mix of both dispatchable and intermittent resources to meet load needs. During that period, Craig 3, LRS 2 & 3, and SPV 3 continue to contribute significantly to meeting capacity needs. In the section above, Tri-State addressed the mix of new semi-dispatchable and dispatchable resources modeled to come online to serve load during the period following the Craig 3 retirement. With the modeled early retirement of Springerville 3 and Burlington Unit 2 coming at the end of the resource planning period, LRS units, existing gas resources including JM Shafer, and the new gas CT will all continue to be available to meet capacity needs, along with the battery additions modeled to occur in 2040 and in years prior. Additionally, Tri-State expects to move a portion, if not all, of its system into a regional transmission organization (RTO) by 2030. While this does not replace the need for Tri-State to acquire and build sufficient capacity to meet resource adequacy and reliability, entry into an organized

market does allow for diversity of resources across a wider footprint which provides for market operator flexibility in meeting changing system conditions.

Burlington Units Analysis

While allowed to retire beginning January 1, 2025, Burlington Unit 1 is not retired during the modeling period, while the model selected a retirement date of January 1, 2040, for Burlington Unit 2. Both Burlington units continue to be available for emergency and contingency power supply, as well as base power supply, when financially feasible throughout 2023-2039 and Burlington Unit 1 remains available through the entire resource planning period.

3. Reduced Load Portfolio

Portfolio 3 (RL) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 39: Expansion Plan (RL)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2030	Gas Combustion Turbine	West Colorado	193	1	193
2031	4hr – Battery	New Mexico	100	1	100
	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
2032	Solar	West Colorado	100	1	100
	4hr -Battery	West Colorado	100	1	100
	Wind (Build Transfer)	New Mexico	100	2	200
	Wind	East Colorado	100	2	200
2033	Wind	East Colorado	100	5	500
	Wind	New Mexico	100	1	100
	Wind	Wyoming/Nebraska	100	4	400
2040	Solar	West Colorado	100	4	400

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- Applicable Colorado energy efficiency targets reflected in base assumptions, but reduced to reflect a reduction in Tri-State Colorado Utility Member load assumed for this portfolio;[85] and
- No additional EE was selected in the expansion plan of the Reduced Load portfolio.

Unit retirements selected in the modeling are shown in the following table.[86]

Table 40: Modeled Retirements (RL)

Location	MW	Technology	Date
Burlington 1	48	Fuel Oil	1/1/2025[87]
Burlington 2	48	Fuel Oil	1/1/2025[88]
Craig 3	448	Coal	12/31/2029

[85] Section 3.11.9. of the Settlement Agreement set energy efficiency targets as a percentage of Tri-State Colorado Utility Member system load.

[86] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.

[87] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire Burlington 1 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its plants.

[88] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire Burlington 2 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its plants.

Springerville 3	419	Coal	1/1/2040[89]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 4: Projected Tri-State System Resource Mix 2030 (RL)[90, 91]

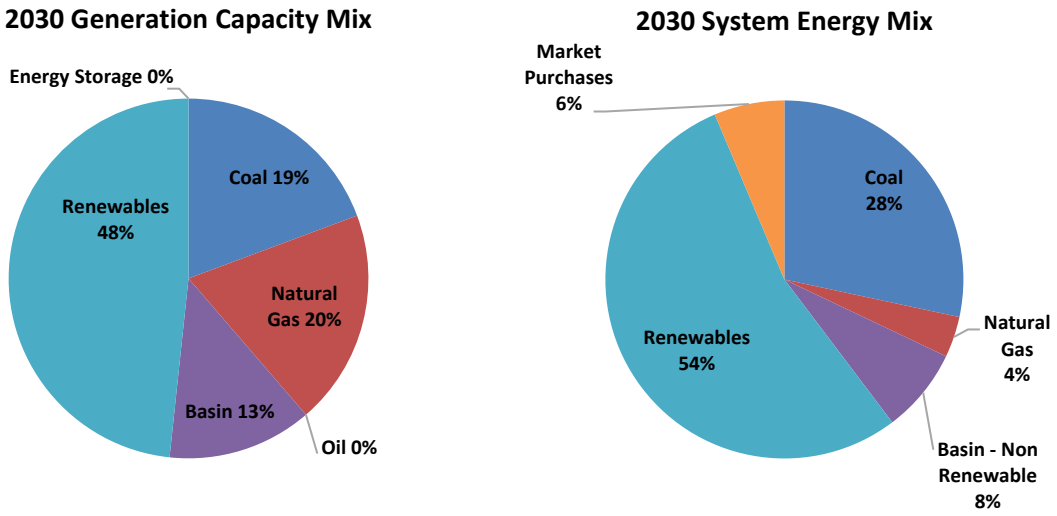


Table 41: Projected Annual Capacity Factors for Thermal Resources (RL)

Thermal Resource	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	73%	80%	66%	40%	0%	0%	0%	0%	0%
Craig 2	86%	84%	93%	22%	29%	22%	5%	0%	0%
Craig 3	73%	90%	65%	59%	54%	41%	32%	19%	0%
LRS 2	51%	81%	67%	82%	69%	81%	80%	80%	69%
LRS 3	54%	70%	57%	45%	60%	50%	43%	39%	62%
SPV3	72%	60%	55%	68%	71%	69%	62%	61%	58%
JM Shafer	16%	5%	1%	3%	6%	7%	12%	19%	11%
Rifle	2%	0%	0%	0%	0%	0%	0%	0%	0%
Limon	2%	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%	0%
Pyramid	8%	10%	0%	9%	6%	7%	7%	7%	6%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%
193MW CT West Colorado	0%	0%	0%	0%	0%	0%	0%	0%	14%

[89] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.

[90] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.

[91] System Energy Mix reflects sales to Members and non-Members.

Portfolio 3 (RL) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

Table 42: Environmental Impact - System Wide (RL)[92]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2022[93]	12,983,932	6,292	10,182	0.2230	409	5,220,513,340	29,493
2023	13,237,222	6,666	10,987	0.2546	429	5,395,640,098	30,622
2024[94]	11,087,650	5,496	8,824	0.1979	340	4,435,807,793	25,674
2025	10,471,242	5,327	8,371	0.1868	320	4,245,183,485	24,111
2026	10,059,770	5,293	7,726	0.1773	323	4,070,649,444	23,008
2027	9,512,743	4,900	7,207	0.1555	300	3,807,554,346	21,420
2028	8,678,490	4,439	6,592	0.1341	270	3,380,086,130	19,011
2029	8,080,886	4,006	5,940	0.1080	248	3,074,530,232	17,182
2030	6,569,383	3,892	5,507	0.0837	256	2,732,011,124	15,689
2031	5,978,207	3,703	5,293	0.0783	230	2,444,079,811	14,508
2032	5,228,723	3,358	4,756	0.0718	202	2,125,729,386	13,077
2033	3,853,089	2,491	3,351	0.0468	125	1,529,484,312	9,927
2034	3,805,926	2,509	3,397	0.0474	129	1,494,548,076	9,747
2035	4,578,489	2,958	4,080	0.0602	167	1,844,389,990	11,556
2036	4,309,312	2,905	4,123	0.0592	168	1,677,848,014	10,723
2037	3,849,101	2,901	4,333	0.0608	190	1,383,322,184	9,164
2038	3,847,021	2,896	4,333	0.0603	189	1,380,118,535	9,145
2039	3,575,346	2,751	4,065	0.0553	171	1,246,981,270	8,545
2040	4,016,764	3,026	4,541	0.0625	195	1,426,369,693	9,549
Total	**133,723,296**	**75,810**	**113,609**	**2.123**	**4,662**	**52,914,847,262**	**312,150**
Pounds/Gallons per MWh[95]	**1,094**	**0.62**	**0.93**	**0.00002**	**0.04**	**217**	**2.82**

[92] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO2, SO2 and NOx are per net MWh; HG and particulate matter (PM) are per gross MWh.
[93] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[94] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.
[95] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 43: Social Cost of Carbon Nominal Dollars – System Wide (RL)

Year	Annual Social Cost of Carbon
2022	$1,038,911,749
2023	$1,106,828,536
2024	$964,775,149
2025	$946,079,762
2026	$943,523,752
2027	$924,167,590
2028	$873,108,319
2029	$841,712,469
2030	$708,296,238
2031	$667,462,468
2032	$604,392,898
2033	$461,005,102
2034	$471,240,142
2035	$586,536,829
2036	$571,064,587
2037	$527,540,797
2038	$545,208,802
2039	$523,857,975
2040	$608,346,446

Table 44: Social Cost of Methane Nominal Dollars – System Wide (RL)

Year	Annual Social Cost of Methane
2022	$67,938,645
2023	$74,460,847
2024	$65,600,846
2025	$64,566,479
2026	$64,535,270
2027	$62,769,154
2028	$58,168,873
2029	$54,862,573
2030	$52,255,251
2031	$50,542,323
2032	$47,623,283
2033	$37,768,152
2034	$38,721,686
2035	$47,907,089
2036	$46,368,896
2037	$41,311,304
2038	$42,962,556
2039	$41,811,227
2040	$48,646,347

Table 45: GHG Emissions Reduction Percentages, Targets and Forecast (RL)

Year[96]	Target[97]	Forecast
2025	26%	58%
2026	36%	64%
2027	46%	67%
2030	80%	83%

See Appendix D for detailed GHG emissions calculations for the portfolio.

Portfolio 3 (RL) – Financial Analysis[98]

The PVRR, NPV of the SCoC and SCoM, total CapEx and IDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 46: Total Financial (RL)

$, Millions	Portfolio PVRR (2022 WACC 4.18%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$15,719.4	$11,349.6	$814.7	$27,069.0	$27,883.7
Expansion Plan CapEx + IDC: Generation (Nominal $)	$603.3				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$544.2				

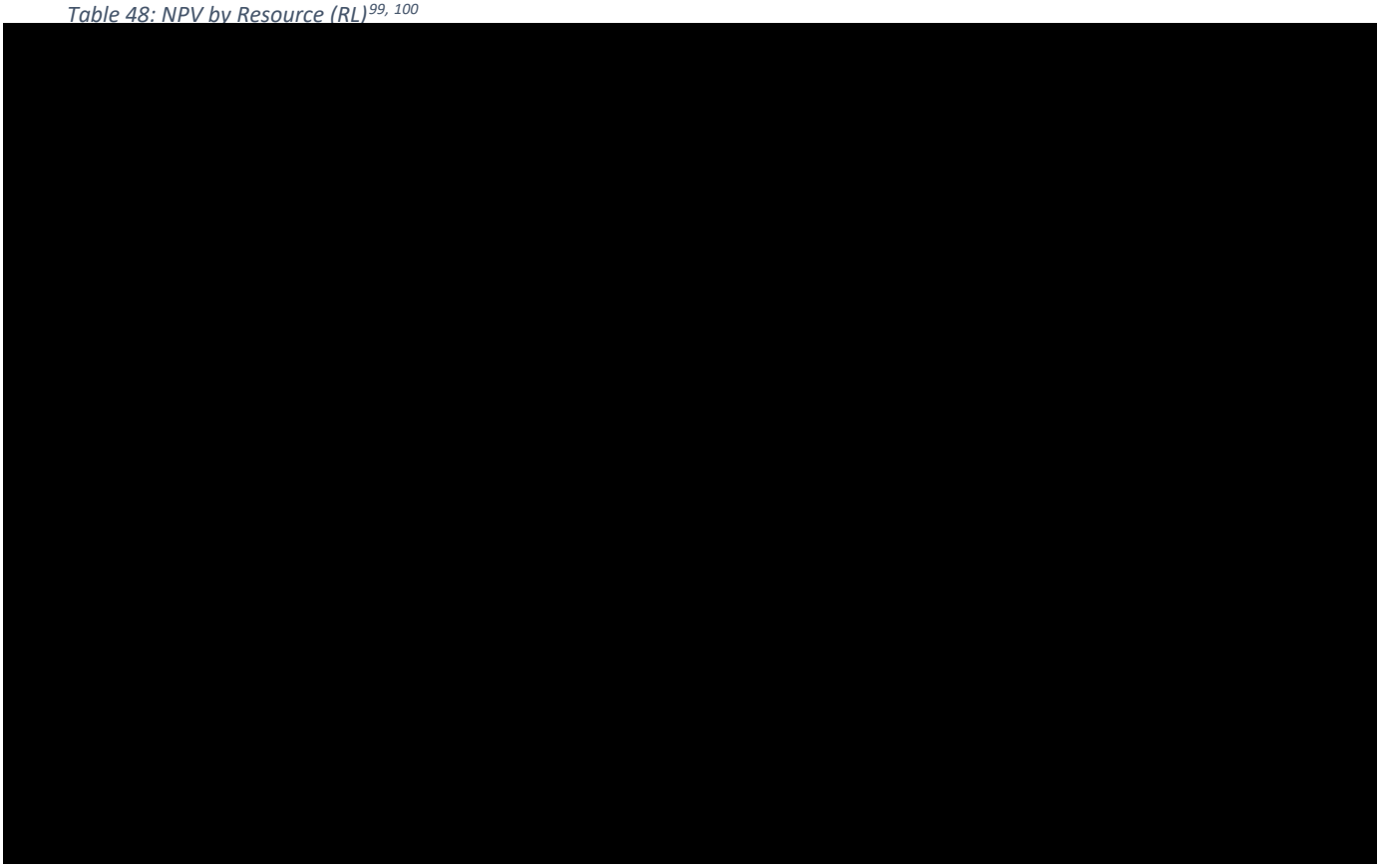
Table 47: Annual Financial (Nominal $) (RL)

Year	Total Annual Revenue Requirement ($, Millions)
2022	$1,176
2023	$1,171
2024	$991
2025	$904
2026	$1,000
2027	$1,066
2028	$1,133

[96] The carbon emission rate assumption for market purchases and sales is 1,280 pounds per MWh through 2029 and 450 pounds per MWh starting in 2030.
[97] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.
[98] Of note, no contract termination payment (CTP) or other items specific to potential Member withdrawal were included in the analysis, as those details were not available at the time of modeling.

2029	$1,185
2030	$1,207
2031	$1,260
2032	$1,324
2033	$1,352
2034	$1,345
2035	$1,342
2036	$1,353
2037	$1,366
2038	$1,375
2039	$1,409
2040	$1,410

Table 48: NPV by Resource (RL)[99, 100]



[99] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[100] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[101] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[102] NPV using 2.5% discount rate
[103] NPV using 2.5% discount rate

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the Reduced Load Portfolio dispatch during the RAP. The majority of curtailments during the RAP are during spring from existing solar.

Table 49: Curtailed Intermittent Energy, Annual MWh (RL)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Bid Wind	Bid Solar	Total
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	48	1,125	0	0	0	0	1,174
2026	34	1,241	0	0	0	0	1,275
2027	0	973	0	0	0	0	973
2028	0	1,359	0	0	0	0	1,359
2029	0	2,197	0	0	0	0	2,197
2030	0	627	0	0	0	0	627
RAP Total	**82**	**7,523**	0	0	0	0	**7,605**

Table 50: Seasonal Renewable Curtailments, Annual MWh (RL)

	Winter	Spring	Summer	Fall
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	121	460	186	406
2026	479	586	30	180
2027	86	843	0	44
2028	180	1,180	0	0
2029	32	2,157	0	8
2030	0	436	6	184
RAP Total	**898**	**5,662**	**223**	**822**

The following table reflects PPA pricing, penalties, and taxes.

Table 51: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (RL)

	Wind ($)	Solar ($)
2022	$0	$0
2023	$0	$0
2024	$0	$0

2025	$2,603	$25,576
2026	$1,671	$30,680
2027	$0	$23,600
2028	$0	$34,157
2029	$0	$66,264
2030	$0	$14,903
RAP Total	**$4,274**	**$195,181**

Portfolio 3 (RL) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[104]

Table 52: Transmission Interconnection & Network Upgrade Expenses (2022 Real $) (RL)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2032	100	Wind		$2.11	
2032	100	Wind		$2.11	
2033	100	Wind		$7.30	
2033	100	Wind		$2.11	
2033	100	Wind		$2.11	
2033	100	Wind		$2.11	
2033	100	Wind		$2.11	
Western Colorado (WCO) Transmission Area					
2030	193	Gas	$1.40	$3.11	
2032	100	Solar		$2.11	
2032	100	Battery	$1.30	$2.21	
2040	100	Solar		$2.21	
2040	100	Solar		$2.21	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
Wyoming (WYO) Transmission Area					
2031	100	Wind (BT)		$3.11	$92.61
2033	100	Wind		$3.11	

[104] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	$26.00
2033	100	Wind		$3.11	
New Mexico (NM) Transmission Area)					
2031	100	Battery	$1.30	$2.21	
2032	100	Wind (BT)		$2.21	$221.98
2032	100	Wind (BT)		$2.21	
2033	100	Wind		$2.21	

Portfolio 3 (RL) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. Analyses of the ability to serve load when Craig 3 is not available and the impact of early retirement of the Burlington units are also provided.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 3 RL.

Table 53: Planning Reserve Margin, % Annual (RL)

2022	2023	2024	2025	2026	2027	2028	2029	2030
17	22	56	80	73	70	69	61	47

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 3 RL.

Table 54: Loss of Load Probability, Hours (RL)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 3 RL.

Table 55: Expected Unserved Energy, Annual MWh (RL)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Ability to Serve Load When Craig 3 Offline

In this portfolio analysis, Craig 3 retires December 31, 2029. To meet reliability metrics (see page 17) starting in 2030, the PRM is increased to 20%. The model selects the following semi-dispatchable and dispatchable resources in 2030: a 193 MW CT Gas unit in WCO. Reliability is met from 2031-2040 with the following battery storage additions: 100 MW in NM, and 100 MW in WCO.

Dispatchable Retirements

Section 3.10.3. of the Settlement Agreement requires a detailed analysis of how load will be served from intermittent resources and Tri-State's other system resources under different service conditions (such as extreme weather events) for any portfolio that includes the retirement of dispatchable resources.

For the Reduced Load portfolio, dispatchable resource retirements selected by the modeling include the Craig units (on the previously announced dates), Burlington Units 1 & 2 in 2025, and Springerville 3 in 2040. Throughout the planning period, Tri-State continues to be capacity-long and maintains a sufficient mix of both dispatchable and intermittent resources to meet load needs. During the 2025-2029 period, Craig 3, LRS 2 & 3, and SPV 3 continue to contribute significantly to meeting capacity needs. In the section above, Tri-State addressed the mix of new intermittent and dispatchable resources modeled to come online to serve load during the period following the Craig 3 retirement. With the modeled early retirement of SPV 3 coming at the end of the resource planning period, LRS units, existing gas resources including JM Shafer, and the new gas CT will all continue to be available to meet capacity needs, along with the battery additions modeled to occur in 2031 and 2032. Additionally, Tri-State expects to move a portion, if not all, of its system into a regional transmission organization (RTO) by 2030. While this does not replace the need for Tri-State to acquire and build sufficient capacity to meet resource adequacy and reliability, entry into an organized market does allow for diversity of resources across a wider footprint which provides for market operator flexibility in meeting changing system conditions.

Burlington Units Analysis

In this analysis, the Burlington units were allowed to retire starting in 2025, and the model selected the retirement of both units on January 1, 2025 given the modeled load reduction starting in mid-2024. Because PRMs are relatively high starting in 2025 and continuing throughout the RAP, and no LoLH or EUE is observed during the planning period, early retirement of the Burlington units in this scenario does not impact reliability, particularly given that these units are primarily operated as contingency reserves. However, the Burlington resources provide fuel diversity to mitigate the impact of extreme operating conditions, and the challenges of fuel supply issues are not evaluated through the extreme weather event sensitivity modeling. The contingency reserve benefits, along with potential market value of the Burlington units following entrance into an RTO, indicate further evaluation of the Burlington resources is necessary to assess the true ongoing viability of the resources.

4. Wind Back-up Bid Portfolio

Portfolio 4 (Wind BKUP) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below. This portfolio was modeled in recognition of the potential risk that Tri-State may not reach acceptable commercial terms will the bidder(s) included in the portfolio approved by the Commission. The bid selected by the model in this backup portfolio would be brought into PPA negotiations in the event negotiations with a primary bidder fail.

Table 56: Expansion Plan (Wind BKUP)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026[105]	Wind (WI-071-1-wyo-wne)	Wyoming/Nebraska	116	1	116
2028	Wind (Build Transfer)	Wyoming/Nebraska	100	2	200
2029	Wind (Build Transfer)	East Colorado	100	3	300
2030	Solar	East Colorado	100	1	100
	Solar	West Colorado	100	4	400
	4 hr - Battery	West Colorado	100	1	100
	4 hr - Battery	West Colorado	25	1	25
	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
	Gas Combustion Turbine	West Colorado	193	1	193
2031	4 hr - Battery	New Mexico	100	1	100
	4 hr - Battery	West Colorado	100	1	100
2032	Wind (Build Transfer)	New Mexico	100	1	100
	Wind (Build Transfer)	Wyoming/Nebraska	100	1	100
	Wind	East Colorado	100	2	200
2033	Wind	East Colorado	100	8	800
	Wind	New Mexico	100	2	200
2034	4 hr - Battery	East Colorado	100	1	100
	Wind	East Colorado	100	1	100
2038	Solar	West Colorado	100	1	100
2039	4 hr - Battery	East Colorado	100	1	100
2040	Solar	West Colorado	100	5	500
	4 hr - Battery	West Colorado	100	1	100

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- No additional EE was selected in the expansion plan of the Wind BKUP portfolio.

[105] This bid has an in-service date in late 2025 (in-service dates are provided in HIGHLY CONFIDENTIAL Attachment C); section 3.4.4.1. of the Settlement Agreement states that a "2026 Bid" is a bid that first contributes to capacity needs in July 2026 and is expected to be online for the majority of 2026 in order to significantly contribute to carbon reduction.

Unit retirements selected in the modeling are shown in the following table.[106]

Table 57: Modeled Retirements (Wind BKUP)

Location	MW	Technology	Date
Craig 3	448	Coal	12/31/2029
Springerville 3	419	Coal	1/1/2040[107]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 5: Projected Tri-State System Resource Mix 2030 (Wind BKUP)[108, 109]

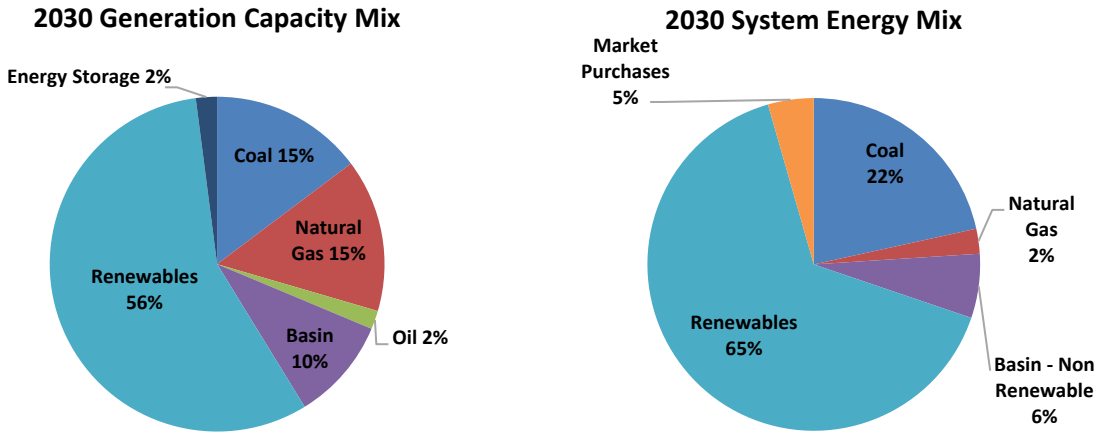


Table 58: Projected Annual Capacity Factors for Thermal Resources (Wind BKUP)

Thermal Resource	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	73%	80%	77%	47%	-	-	-	-	-
Craig 2	86%	84%	93%	31%	25%	4%	4%	-	-
Craig 3	73%	90%	79%	66%	63%	43%	29%	19%	-
LRS 2	51%	81%	70%	83%	70%	79%	79%	79%	65%
LRS 3	54%	70%	62%	47%	61%	49%	45%	37%	56%
SPV3	72%	60%	56%	69%	71%	69%	62%	61%	55%
JM Shafer	16%	5%	5%	23%	24%	47%	44%	33%	11%

[106] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.
[107] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.
[108] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[109] System Energy Mix reflects sales to Members and non-Members.

Rifle	2%	-	-	-	-	-	-	-	-
Limon	2%	0%	0%	0%	0%	0%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	0%	0%	0%	0%
Pyramid	8%	10%	1%	13%	9%	11%	10%	8%	4%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%
193MW CT West Colorado	-	-	-	-	-	-	-	-	8%

Portfolio 4 (Wind BKUP) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

Table 59: Environmental Impact - System Wide (Wind BKUP)[110]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2022[111]	12,983,932	6,292	10,182	0.2230	409	5,220,513,340	29,493
2023	13,236,948	6,666	10,987	0.2547	429	5,396,587,708	30,624
2024[112]	12,080,369	6,028	9,842	0.2264	379	4,903,055,968	28,125
2025	11,390,382	5,633	9,138	0.2014	359	4,659,951,422	25,685
2026	10,820,886	5,609	8,431	0.1939	357	4,421,916,594	24,292
2027	10,179,424	5,003	7,752	0.1573	336	4,083,536,507	21,605
2028	9,224,221	4,478	6,930	0.1298	302	3,594,374,130	19,119
2029	8,378,388	4,038	6,131	0.1080	260	3,177,557,763	17,327
2030	6,121,079	3,665	5,147	0.0779	235	2,560,364,406	14,940
2031	5,857,912	3,679	5,222	0.0774	227	2,384,942,758	14,347
2032	5,023,844	3,261	4,547	0.0668	191	2,014,872,575	12,664
2033	3,347,732	2,229	2,883	0.0370	99	1,279,455,811	8,787
2034	3,345,868	2,265	2,968	0.0386	106	1,270,854,847	8,678
2035	3,535,464	2,343	3,049	0.0400	108	1,360,768,954	9,203
2036	3,258,394	2,309	3,110	0.0390	111	1,181,698,711	8,365
2037	2,889,591	2,302	3,359	0.0413	127	939,510,395	6,894
2038	2,721,615	2,205	3,194	0.0373	116	853,187,711	6,488
2039	2,810,342	2,276	3,297	0.0391	120	882,408,611	6,709
2040	3,094,990	2,463	3,612	0.0434	135	990,367,615	7,348
Total	**130,301,381**	**72,743**	**109,784**	**2.032**	**4,405**	**51,175,925,825**	**300,692**
Pounds/Gallons per MWh[113]	**837**	**0.47**	**0.71**	**0.00001**	**0.03**	**164**	**2.13**

[110] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO2, SO2 and NOx are per net MWh; HG and particulate matter (PM) are per gross MWh.
[111] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[112] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.
[113] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 60: Social Cost of Carbon Nominal Dollars – System Wide (Wind BKUP)

Year	Annual Social Cost of Carbon
2022	$1,038,911,749
2023	$1,106,805,608
2024	$1,051,155,113
2025	$1,029,124,333
2026	$1,014,910,237
2027	$988,936,015
2028	$928,012,132
2029	$872,700,561
2030	$659,961,101
2031	$654,031,611
2032	$580,710,726
2033	$400,541,322
2034	$414,276,946
2035	$452,917,981
2036	$431,798,180
2037	$396,034,584
2038	$385,713,731
2039	$411,769,874
2040	$468,741,984

Table 61: Social Cost of Methane Nominal Dollars – System Wide (Wind BKUP)

Year	Annual Social Cost of Methane
2022	$67,938,645
2023	$74,466,457
2024	$71,863,757
2025	$68,782,366
2026	$68,134,628
2027	$63,310,329
2028	$58,499,634
2029	$55,326,786
2030	$49,759,438
2031	$49,981,293
2032	$46,120,928
2033	$33,432,041
2034	$34,472,523
2035	$38,151,526
2036	$36,171,194
2037	$31,078,571
2038	$30,480,425
2039	$32,827,839
2040	$37,433,762

Table 62: GHG Emissions Reduction Percentages, Targets and Forecast (Wind BKUP)

Year[114]	Target[115]	Forecast
2025	26%	33%
2026	36%	41%
2027	46%	48%
2030	80%	81%

See Appendix D for detailed GHG emissions calculations for the portfolio.

Portfolio 4 (Wind BKUP) – Financial Analysis

The PVRR, NPV of the SCoC and SCoM, total CapEx and IDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 63: Total Financial (Wind BKUP)

$, Millions	**Portfolio PVRR** (2022 WACC 4.18%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$18,501.8	$10,998.7	$777.0	$29,500.5	$30,277.5
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,481.5				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$1,754.8				

Table 64: Annual Financial (Nominal $) (Wind BKUP)

Year	Total Annual Revenue Requirement ($, Millions)
2022	$ 1,176
2023	$ 1,171
2024	$ 1,137
2025	$ 1,114
2026	$ 1,204
2027	$ 1,276
2028	$ 1,352
2029	$ 1,406

[114] The carbon emission rate assumption for market purchases and sales is 1,280 pounds per MWh through 2029 and 450 pounds per MWh starting in 2030.
[115] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.

2030	$	1,482
2031	$	1,573
2032	$	1,579
2033	$	1,602
2034	$	1,622
2035	$	1,637
2036	$	1,650
2037	$	1,653
2038	$	1,672
2039	$	1,711
2040	$	1,727

Table 65: NPV by Resource (Wind BKUP)[116, 117]



[116] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[117] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[118] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[119] NPV using 2.5% discount rate
[120] NPV using 2.5% discount rate



Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the Wind BKUP portfolio, through 2029. In 2030, with the addition of 600 MW of intermittent resources, 125 MW of batteries, and the retirement of Craig 3 we begin to see more substantial curtailments – primarily impacting solar and occurring in the spring season. Total financial curtailment costs in 2030 exceed $3.8 million, as shown in Table 68 below, and reflect 90% of the curtailment costs over the RAP.

Table 66: Curtailed Intermittent Energy, Annual MWh (Wind BKUP)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Bid Wind	Bid Solar	Total
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	0	218	0	0	0	0	218
2026	3	1,212	0	0	0	0	1,215
2027	0	2,605	0	0	0	0	2,605
2028	0	2,257	0	0	0	0	2,257
2029	1,121	8,510	0	0	0	0	9,631
2030	24,754	32,848	4,885	83,797	663	0	146,948
RAP Total	**25,878**	**47,651**	**4885**	**83,797**	**663**	**0**	**162,876**

Table 67: Seasonal Renewable Curtailments, Annual MWh (Wind BKUP)

	Winter	Spring	Summer	Fall
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	0	183	3	32
2026	197	973	0	45
2027	81	2,385	49	91
2028	186	2,071	0	0
2029	147	9,117	110	257
2030	10,331	115,961	8,085	12,571
RAP Total	**10,943**	**130,689**	**8,247**	**12,997**

The following table reflects PPA pricing, penalties, and taxes.

Table 68: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (Wind BKUP)

	Wind ($)	Solar ($)
2022	$0	$0
2023	$0	$0
2024	$0	$0
2025	$0	$5,769
2026	$142	$34,621
2027	$0	$76,523
2028	$0	$56,558
2029	$46,309	$205,880
2030	$1,196,647	$2,639,204
RAP Total	**$1,243,097**	**$3,018,556**

Portfolio 4 (Wind BKUP) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[121]

Table 69: Transmission Interconnection & Network Upgrade Expenses (2022 Real $) (Wind BKUP)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	100	Wind (BT)		$2.21	

[121] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2029	100	Wind (BT)		$2.21	
2029	100	Wind (BT)		$2.21	
2030	100	Solar		$2.21	
2032	100	Wind		$2.21	
2032	100	Wind		$2.21	
2033	100	Wind		$7.30	
2033	100	Wind		$2.21	
2033	100	Wind		$3.11	$836.22
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2034	100	Wind		$3.11	
2034	100	Battery	$1.30	$2.21	
2039	100	Battery	$1.30	$2.21	
Western Colorado (WCO) Transmission Area					
2030	193	Gas	$1.40	$3.11	
2030	100	Solar		$2.21	
2030	100	Solar		$2.21	
2030	100	Solar		$2.21	
2030	100	Solar		$2.21	
2030	100	Battery	$1.30	$2.21	
2030	25	Battery	$1.20	$1.22	
2031	100	Battery	$1.40	$3.11	
2038	100	Solar		$3.11	
2040	100	Solar		$9.98	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
2040	100	Solar		$3.11	
2040	100	Battery	$1.40	$3.11	
Wyoming (WYO) Transmission Area					
2025	116	Wind		$1.22	
2028	100	Wind (BT)		$3.11	$92.61
2028	100	Wind (BT)		$3.11	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2030	100	Wind (BT)		$3.11	
2032	100	Wind (BT)		$3.11	$26.00
New Mexico (NM) Transmission Area)					
2031	100	Battery	$1.30	$2.21	
2032	100	Wind (BT)		$2.21	$221.98
2033	100	Wind		$2.21	
2033	100	Wind		$2.21	

Portfolio 4 (Wind BKUP) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. Analyses of the ability to serve load when Craig 3 is not available is also provided.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 4 Wind BKUP.

Table 70: Planning Reserve Margin, % Annual (Wind BKUP)

2022	2023	2024	2025	2026	2027	2028	2029	2030
17	22	25	40	35	32	33	29	28

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 4 Wind BKUP.

Table 71: Loss of Load Probability, Hours (Wind BKUP)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	1

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 4 Wind BKUP.

Table 72: Expected Unserved Energy, Annual MWh (Wind BKUP)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	6

Ability to Serve Load When Craig 3 Offline

In this portfolio analysis, Craig 3 retires December 31, 2029. To meet reliability metrics (see page 17) starting in 2030, the minimum PRM is increased to 20%. The model selects the following semi-dispatchable and dispatchable resources in 2030: 125 MW of batteries in WCO and a 193 MW CT gas unit in WCO. Reliability is met from 2031-2040 with the following battery storage additions: 100 MW in NM, 200 MW in ECO, and 200 MW in WCO.

Dispatchable Retirements

As described in Attachment B-3, unit retirements were not altered from the Revised Preferred Plan portfolio for the Wind BKUP portfolio. See Dispatchable Retirements discussion above for the Revised Preferred Plan portfolio.

5. Craig 3 Early Retirement Portfolio

Portfolio 5 (EC3) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 73: Expansion Plan (EC3)

Year	Technology	Planning Region	Unit Size (MW)	Number of Units	Total MW
2026[122]	Solar (PC-PV-030-1-eco) / Battery (PC-ST-030-1-eco)	East Colorado	200	1	200
2026	Wind (WI-028-1-wyo-wne)	Wyoming/Nebraska	200	1	200
2027	Solar/Battery Hybrid*	West Colorado	100	6	600
	4 hr - Battery	East Colorado	100	3	300
	4 hr - Battery	East Colorado	25	2	50
2028	Solar/Battery Hybrid*	West Colorado	100	2	200
	Wind (Build Transfer)	East Colorado	100	1	100
	Wind (Build Transfer)	Wyoming/Nebraska	100	2	200
2029	Solar/Battery Hybrid*	West Colorado	100	5	500
	Wind (Build Transfer)	East Colorado	100	3	300
	Wind/Battery Hybrid*	East Colorado	100	1	100
	Wind/Battery Hybrid*	Wyoming/Nebraska	100	1	100
2030	Wind (Build Transfer)	East Colorado	100	1	100
2031	4 hr - Battery	West Colorado	100	2	200
2032	Wind	New Mexico	100	3	300
2033	Wind	East Colorado	100	9	900
	Wind	Wyoming/Nebraska	100	1	100

*Generic hybrids include 25 MW/100 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- No additional EE was selected in the expansion plan of the EC3 portfolio.

Unit retirements selected in the modeling are shown in the following table.[123]

[122] This bid has an in-service date in late 2025 (in-service dates are provided in HIGHLY CONFIDENTIAL Attachment C); section 3.4.4.1. of the Settlement Agreement states that a "2026 Bid" is a bid that first contributes to capacity needs in July 2026 and is expected to be online for the majority of 2026 in order to significantly contribute to carbon reduction.

[123] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.

Table 74: Modeled Retirements (EC3)

Location	MW	Technology	Date
Craig 3	448	Coal	1/1/2027
Springerville 3	419	Coal	1/1/2037[124]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 6: Projected Tri-State System Resource Mix 2030 (EC3)[125, 126]

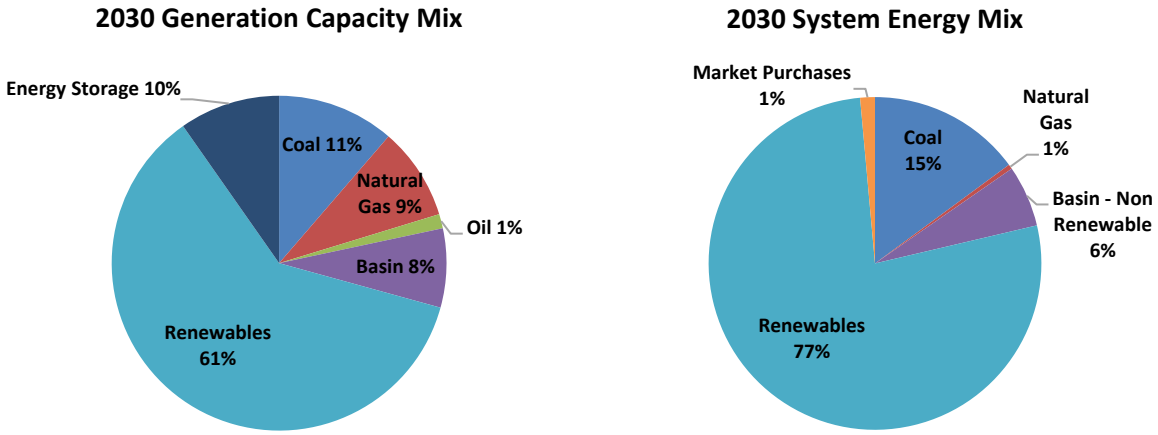


Table 75: Projected Annual Capacity Factors for Thermal Resources (EC3)

Thermal Resource	2022	2023	2024	2025	2026	2027	2028	2029	2030
Craig 1	73%	80%	78%	43%	-	-	-	-	-
Craig 2	86%	84%	93%	37%	36%	77%	60%	-	-
Craig 3	73%	90%	77%	66%	60%	-	-	-	-
LRS 2	51%	81%	71%	83%	70%	84%	75%	60%	48%
LRS 3	54%	70%	63%	48%	67%	79%	67%	49%	36%
SPV 3	72%	60%	56%	69%	70%	66%	55%	48%	43%
JM Shafer	16%	5%	4%	21%	10%	24%	14%	6%	4%
Rifle	2%	-	-	-	-	-	-	-	-
Limon	2%	0%	0%	0%	0%	1%	0%	0%	0%
Knutson	1%	0%	0%	0%	0%	1%	0%	0%	0%
Pyramid	8%	10%	1%	13%	6%	5%	3%	1%	0%
Burlington	0%	0%	0%	0%	0%	0%	0%	0%	0%

[124] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.
[125] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[126] System Energy Mix reflects sales to Members and non-Members.

Portfolio 5 (EC3) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

Table 76: Environmental Impact - System Wide (EC3)[127]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2022[128]	12,983,932	6,292	10,182	0.2230	409	5,220,513,340	29,493
2023	13,238,415	6,668	10,992	0.2549	429	5,398,945,303	30,634
2024[129]	12,078,302	6,016	9,828	0.2243	380	4,896,272,045	28,072
2025	11,387,401	5,636	9,088	0.2009	359	4,655,093,155	25,717
2026	10,720,411	5,650	8,326	0.1930	354	4,350,217,713	24,493
2027	9,404,897	4,519	6,539	0.1073	334	3,671,346,512	20,078
2028	8,013,305	3,988	5,683	0.0918	277	3,008,538,322	17,088
2029	6,239,451	3,241	4,447	0.0694	199	2,226,785,161	13,284
2030	4,402,419	2,762	3,710	0.0550	154	1,821,237,967	11,301
2031	4,230,638	2,738	3,743	0.0548	152	1,707,278,207	10,816
2032	3,541,268	2,356	3,149	0.0433	117	1,380,520,926	9,427
2033	2,371,859	1,629	1,961	0.0209	50	859,245,830	6,673
2034	2,434,623	1,704	2,109	0.0235	60	877,015,375	6,702
2035	2,634,155	1,799	2,217	0.0257	65	973,336,940	7,266
2036	2,536,532	1,863	2,434	0.0290	81	892,590,633	6,868
2037	2,097,369	1,755	2,481	0.0284	85	643,660,709	5,008
2038	2,168,986	1,812	2,554	0.0299	90	673,512,067	5,174
2039	2,274,365	1,888	2,665	0.0319	97	716,853,102	5,426
2040	2,752,770	2,202	3,195	0.0399	121	901,905,039	6,564
Total	**115,511,098**	**64,519**	**95,303**	**1.747**	**3,813**	**44,874,868,345**	**270,085**
Pounds/Gallons per MWh[130]	**742**	**0.41**	**0.61**	**0.00001**	**0.02**	**144**	**1.91**

Table 77: Social Cost of Carbon Nominal Dollars – System Wide (EC3)

Year	Annual Social Cost of Carbon
2022	$1,038,911,749
2023	$1,106,928,295
2024	$1,050,975,226
2025	$1,028,854,964
2026	$1,005,486,454
2027	$913,690,373

[127] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO2, SO2 and NOx are per net MWh; HG and particulate matter (PM) are per gross MWh.
[128] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[129] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.
[130] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

2028	$806,186,716
2029	$649,906,908
2030	$474,658,928
2031	$472,347,719
2032	$409,338,399
2033	$283,782,481
2034	$301,448,912
2035	$337,453,880
2036	$336,137,939
2037	$287,456,177
2038	$307,393,820
2039	$333,238,841
2040	$416,912,104

Table 78: Social Cost of Methane Nominal Dollars – System Wide (EC3)

Year	Annual Social Cost of Methane
2022	$67,938,645
2023	$74,491,110
2024	$71,728,358
2025	$68,866,647
2026	$68,698,619
2027	$58,836,508
2028	$52,285,011
2029	$42,417,929
2030	$37,640,895
2031	$37,680,362
2032	$34,330,170
2033	$25,389,611
2034	$26,624,745
2035	$30,123,995
2036	$29,697,905
2037	$22,576,585
2038	$24,306,819
2039	$26,551,725
2040	$33,441,978

Table 79: GHG Emissions Reduction Percentages, Targets and Forecast (EC3)

Year[131]	Target[132]	Forecast
2025	26%	34%
2026	36%	45%
2027	46%	58%
2030	80%	82%

[131] The carbon emission rate assumption for market purchases and sales is 1,280 pounds per MWh through 2029 and 450 pounds per MWh starting in 2030.
[132] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.

See Appendix D for detailed GHG emissions calculations for the portfolio.

Portfolio 5 (EC3) – Financial Analysis

The PVRR, NPV of the SCoC and SCoM, total CapEx and IDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 80: Total Financial (EC3)

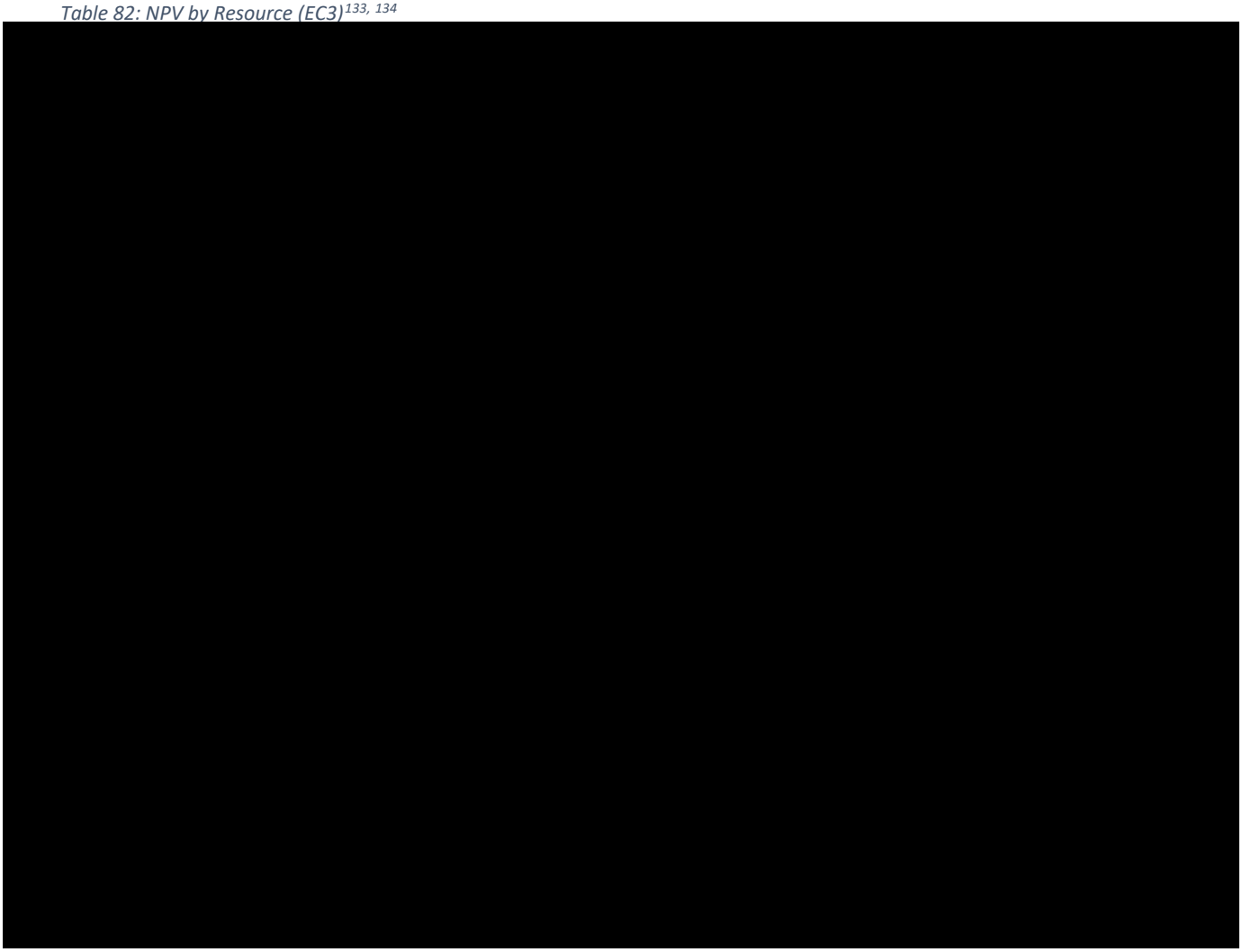
$, Millions	**Portfolio PVRR** (2022 WACC 4.18%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$18,879.0	$9,695.1	$691.3	$28,574.2	$29,265.5
Expansion Plan CapEx + IDC: Generation (Nominal $)	$1,379.3				
Expansion Plan CapEx + IDC: Transmission (Nominal $)	$1,677.7				

Table 81: Annual Financial (Nominal $) (EC3)

Year	**Total Annual Revenue Requirement ($, Millions)**
2022	$1,176
2023	$1,186
2024	$1,155
2025	$1,153
2026	$1,264
2027	$1,453
2028	$1,523
2029	$1,432
2030	$,1481
2031	$1,582
2032	$1,606
2033	$1,645
2034	$1,663
2035	$1,669
2036	$1,665
2037	$1,604
2038	$1,620

2039	$1,654
2040	$1,626

Table 82: NPV by Resource (EC3)[133, 134]



Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

[133] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[134] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[135] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[136] NPV using 2.5% discount rate
[137] NPV using 2.5% discount rate

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the EC3 dispatch, through 2026. In 2027 through 2030, with the addition of 700 MW of intermittent resources, 1,500 MW of intermittent resources paired with battery storage (hybrids), 350 MW of batteries, and the retirement of Craig 3 we begin to see more substantial curtailments – most significantly impacting solar and occurring in the spring season. By 2029, the total financial curtailment cost exceeds $29 million and reflect approximately 40% of the curtailment costs over the RAP. Total financial curtailment costs in 2030 exceed $34 million, as shown in Table 85 below, and reflect 47% of the curtailment costs over the RAP.

Table 83: Curtailed Intermittent Energy, Annual MWh (EC3)

	Existing Wind	Existing Solar	Generic Wind	Generic Solar	Bid Wind	Bid Solar	Total
2022	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0
2025	0	617	0	0	0	137	754
2026	0	3,056	0	0	0	1,152	4,208
2027	566	6,321	0	22,876	0	3,752	33,515
2028	11,215	20,800	533	188,169	97	17,772	238,585
2029	53,242	55,247	21,305	971,853	3,350	64,604	1,169,601
2030	113,889	92,920	67,778	979,905	2,733	103,345	1,360,570
RAP Total	**178,912**	**178,961**	**89,616**	**2,162,802**	**6,180**	**190,762**	**2,807,233**

Table 84: Seasonal Renewable Curtailments, Annual GWh (EC3)

	Winter	Spring	Summer	Fall
2022	0	0	0	0
2023	0	0	0	0
2024	0	0	0	0
2025	35	399	0	320
2026	436	2,716	211	844
2027	617	26,148	3,940	2,811
2028	7,335	153,679	53,276	24,295
2029	95,583	544,000	327,709	202,308
2030	163,229	622,166	334,726	240,449
RAP Total	**267,234**	**1,349,109**	**719,863**	**471,028**

The following table reflects PPA pricing, penalties, and taxes.

Table 85: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (EC3)

	Wind ($)	Solar ($)
2022	$0	$0
2023	$0	$0
2024	$0	$0
2025	$0	$18,286

2026	$0	$96,989
2027	$24,255	$923,683
2028	$474,847	$6,389,605
2029	$3,151,858	$26,096,716
2030	$7,102,829	$27,121,912
RAP Total	**$10,753,789**	**$60,647,191**

Portfolio 5 (EC3) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[138]

Transmission Available Transmission Capacity Adjustments – Portfolio 5 (EC3)

Given the extensive amount (2,950 MW during the RAP) of new resources modeled for the EC3 expansion plan, additional transmission capacity reservations were modeled to reflect the transmission that would be necessary from eastern Colorado into western Colorado (ECO > WCO) to accommodate the additions. Associated transmission capacity reservation costs are also reflected in the financial modeling. The specific additional third-party transmission purchase details are provided in Attachment B-3.

Table 86: Transmission Interconnection & Network Upgrade Expenses (2022 Real $) (EC3)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2025	200	Solar + Battery		$7.30	
2027	100	Battery	1.3	$2.21	
2027	100	Battery	1.3	$2.21	
2027	100	Battery	1.3	$2.21	
2027	25	Battery	1.2	$1.22	
2027	25	Battery	1.2	$1.22	
2028	100	Wind - BT		$2.21	
2029	100	Wind - BT		$2.21	
2029	100	Wind - BT		$2.21	
2029	100	Wind - BT		$2.21	
2029	100	Wind + Battery		$3.11	$836.22
2030	100	Wind - BT		$3.11	

[138] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
2033	100	Wind		$3.11	
Western Colorado (WCO) Transmission Area					
2027	100	Solar + Battery		$3.11	
2027	100	Solar + Battery		$3.11	
2027	100	Solar + Battery		$3.11	
2027	100	Solar + Battery		$3.11	
2027	100	Solar + Battery		$2.21	
2027	100	Solar + Battery		$2.21	
2028	100	Solar + Battery		$9.98	
2028	100	Solar + Battery		$3.11	
2029	100	Solar + Battery		$2.21	
2029	100	Solar + Battery		$2.21	
2029	100	Solar + Battery		$2.21	
2029	100	Solar + Battery		$1.22	
2029	100	Solar + Battery		$1.22	
2031	100	Battery	1.3	$2.21	
2031	100	Battery	1.3	$2.21	
Wyoming (WYO) Transmission Area					
2026	200	Wind		$9.98	
2028	100	Wind - BT		$9.98	$92.61
2028	100	Wind - BT		$3.11	
2029	100	Wind + Battery		$3.11	$26.00
2033	100	Wind		$3.11	
New Mexico (NM) Transmission Area)					
2032	100	Wind		$2.21	$221.98
2032	100	Wind		$2.21	
2032	100	Wind		$2.21	

Portfolio 5 (EC3) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. An analysis of the ability to serve load when Craig 3 is not available is also provided.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 5 EC3.

Table 87: Planning Reserve Margin, % Annual (EC3)

2022	2023	2024	2025	2026	2027	2028	2029	2030
17	22	25	42	39	42	46	53	54

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 5 EC3.

Table 88: Loss of Load Probability, Hours (EC3)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 5 EC3.

Table 89: Expected Unserved Energy, Annual MWh (EC3)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031-2040
0	0	0	0	0	0	0	0	0	0

Ability to Serve Load When Craig 3 Offline

In this portfolio analysis, Craig 3 retires January 1, 2027.[139] To meet reliability metrics (see page 17) starting in 2027, the PRM is increased to 20%. The model selects the following semi-dispatchable resources in 2027-2030: 350 MW of stand-alone batteries in ECO and 375 MW of batteries for hybrid units (325 MW of batteries in WCO, 25 MW of batteries in ECO, and 25 MW of batteries in WYO). Reliability is met from 2031-2040 with the following battery storage additions: 200 MW in WCO. In order to enable the software model to meet transmission and build limits for the portfolio and Level II reliability criteria for the extreme weather sensitivity, 1,300 MW of solar/hybrid battery units were forced into WCO during the 2027-2029 timeframe. As modeled in this portfolio, by 2030, renewables are forecasted to make up 61% of generation capacity while storage makes up 10% of the generation capacity mix. The balance of the mix is made up of thermal and contract resources.

Dispatchable Retirements

This portfolio retires Craig 3 on January 1, 2027 and does not bring any dispatchable resources online for replacement capacity. A tremendous amount (nearly 3,000 MW during the RAP) of new renewable and semi-dispatchable resources were modeled to be required in order to meet reliability criteria, including during EWEs. This results in PRMs that are roughly 10-20% higher than the other portfolios[140] starting in 2027. The ability to procure and integrate this significant level of new resources into the system is questionable.

[139] Settlement Agreement section 3.7.4. identifies a retirement window of July 1, 2025 through December 31, 2026; however, software modeling requires January 1 retirement dates. This modeling limitation was discussed in a stakeholder meeting conveyed May 24, 2022.

[140] RL portfolio excluded from comparison, due to dissimilar load modeled.

Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase II portfolio is provided below.

Environmental Analysis

The following tables identify each portfolio's system-wide forecasted CO_2 and CH_4 emissions in 2025 and 2030.

Figure 7: Comparison of Forecasted CO_2 Emissions in 2025 and 2030, by Portfolio

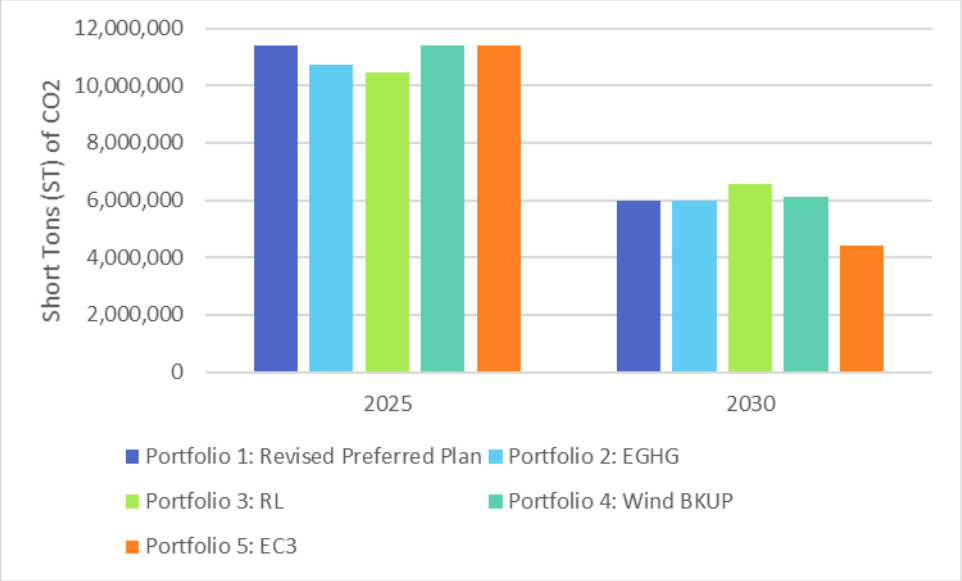
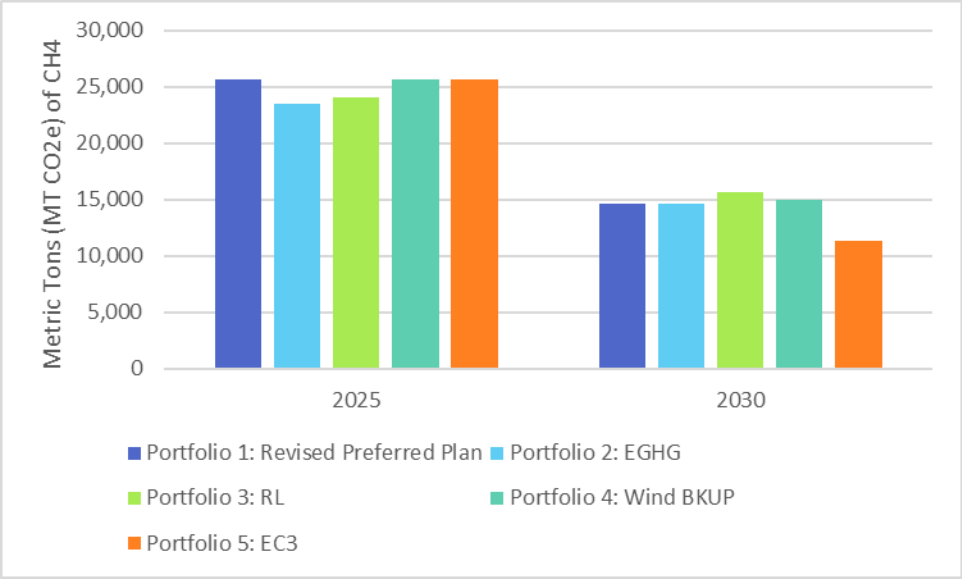


Figure 8: Comparison of Forecasted CH_4 Emissions in 2025 and 2030, by Portfolio



The following table identifies each portfolio's forecasted achievements toward Colorado GHG reduction targets. Notably, Portfolio 2 (EGHG) results are driven by the underlying modeling assumption forcing achievement of the targets one year earlier than the other portfolios. Additionally, Portfolio 3 (RL)

demonstrates significant carbon reduction with no additional renewable resources in the RAP as a result of removing United Power's load (which has grown substantially since 2005) from both the baseline and forecast. While Portfolios 2 (EGHG) and 5 (EC3) have lower Colorado GHG emissions than the Revised Preferred Plan, those outcomes are the result of modeling input assumptions that raise concerns regarding their technical or financial feasibility. As shown in Table 92 below, the model selects a significant level of new resource acquisitions in the EC3 portfolio, which would create serious financial and reliability implications if this portfolio were to be implemented. Similarly, the EGHG portfolio brings forward an additional resource during this acquisition period which increases near-term annual revenue requirements for Tri-State Members. At this time of continued load uncertainty and utility system transitions, maintaining steady incremental progress toward Colorado's GHG reduction targets is best achieved by implementation of the Revised Preferred Plan. Tri-State supports the Revised Preferred Plan because it achieves the right balance of reliability, affordability, and responsibility expected by its Members.

Additional discussion of Tri-State's consideration of the environmental results of the portfolio analyses can be found in the Portfolio Analysis section of the Executive Summary; and discussion of SCoC and SCoM in the Financial Analysis section below.

Table 90: Comparison of Portfolio Achievements Toward Colorado GHG Reduction Targets

	2025	2026	2027	2030
Portfolio 1: Revised Preferred Plan	33%	43%	49%	81%
Portfolio 2: EGHG	41%	52%	61%	81%
Portfolio 3: RL	58%	64%	67%	83%
Portfolio 4: Wind BKUP	33%	41%	48%	81%
Portfolio 5: EC3	34%	45%	58%	82%

Figure 9: Comparison of Portfolio Achievements Toward Colorado GHG Reduction Targets

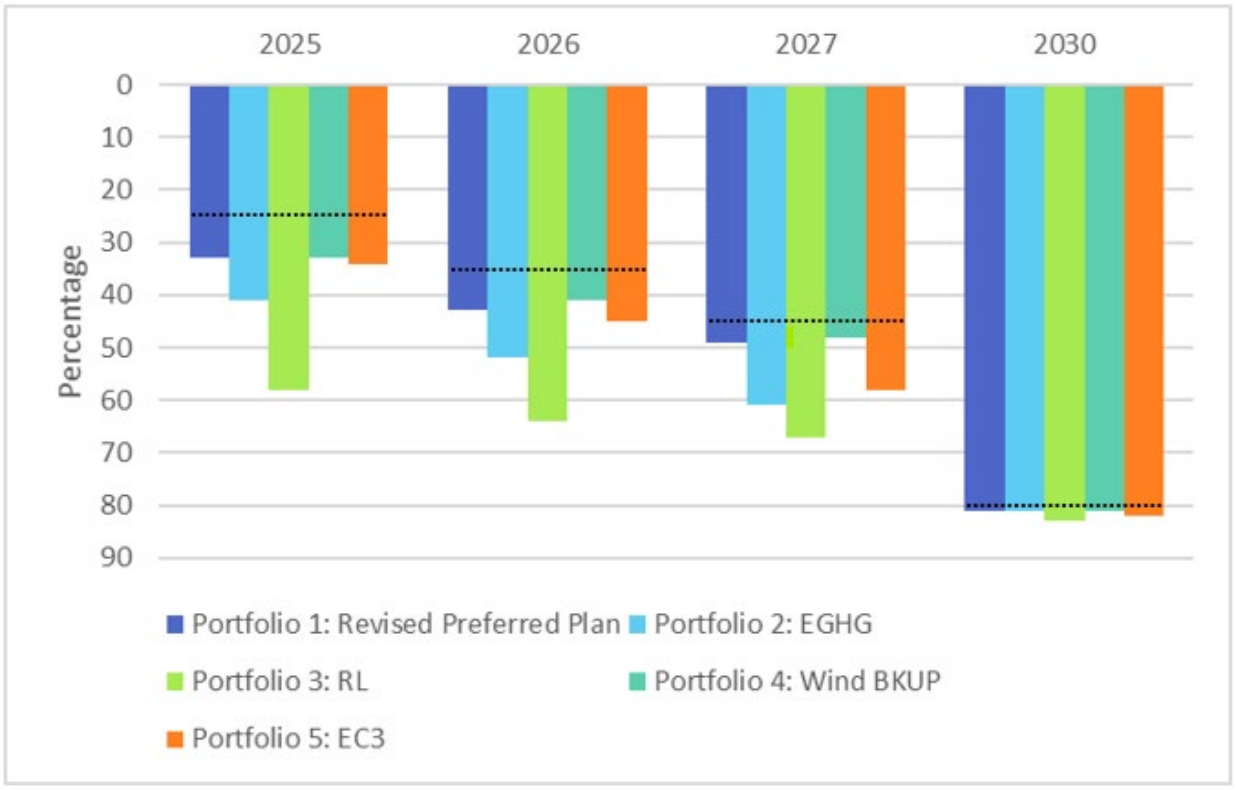


Figure 10: Comparison of Colorado CO2e

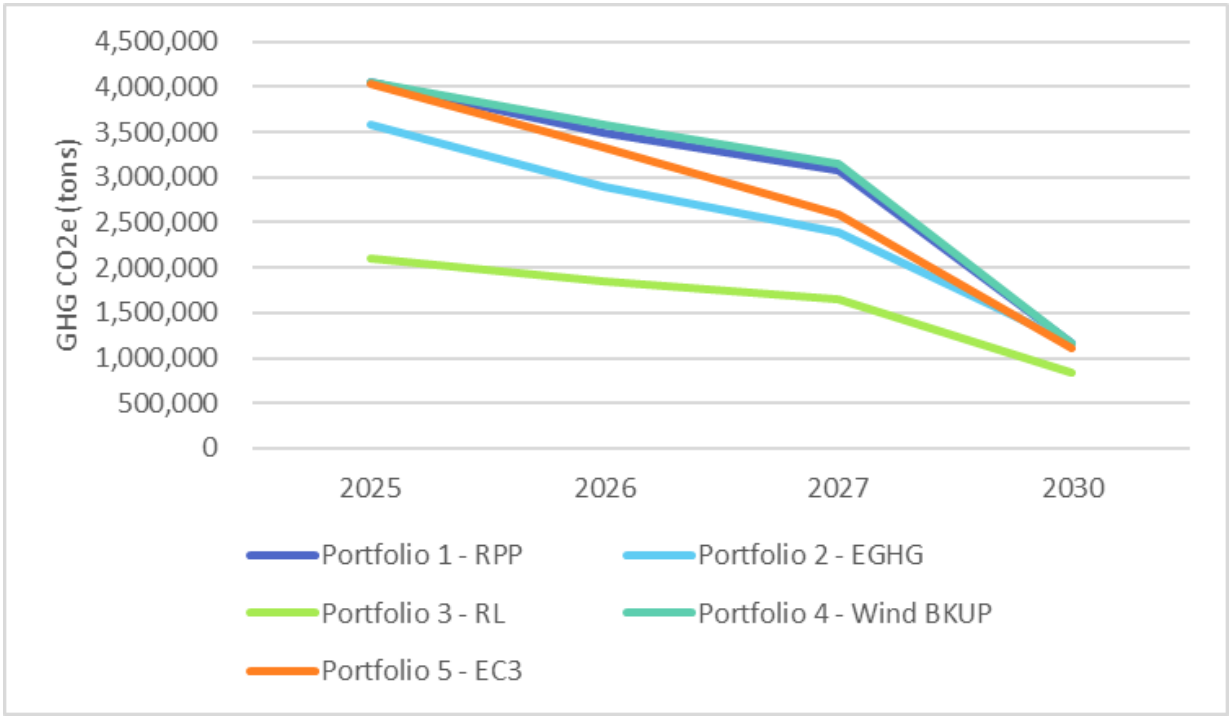


Figure 11: Comparison of SCoC

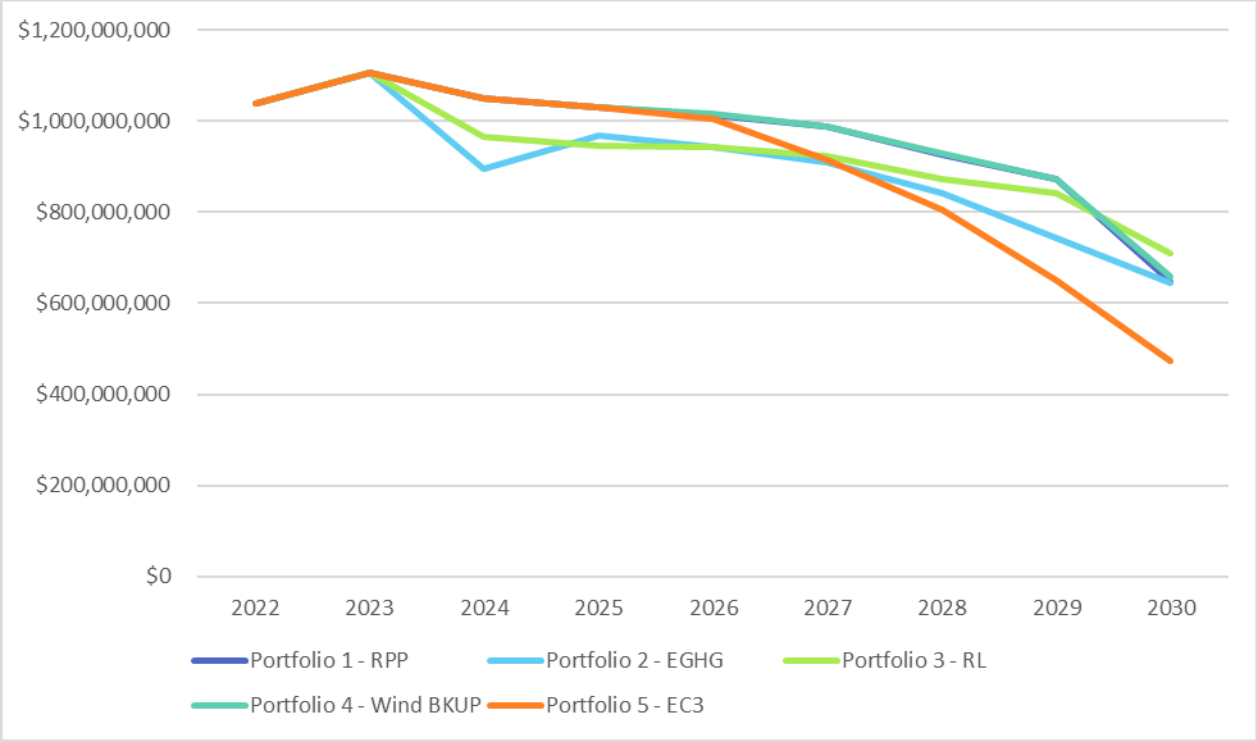
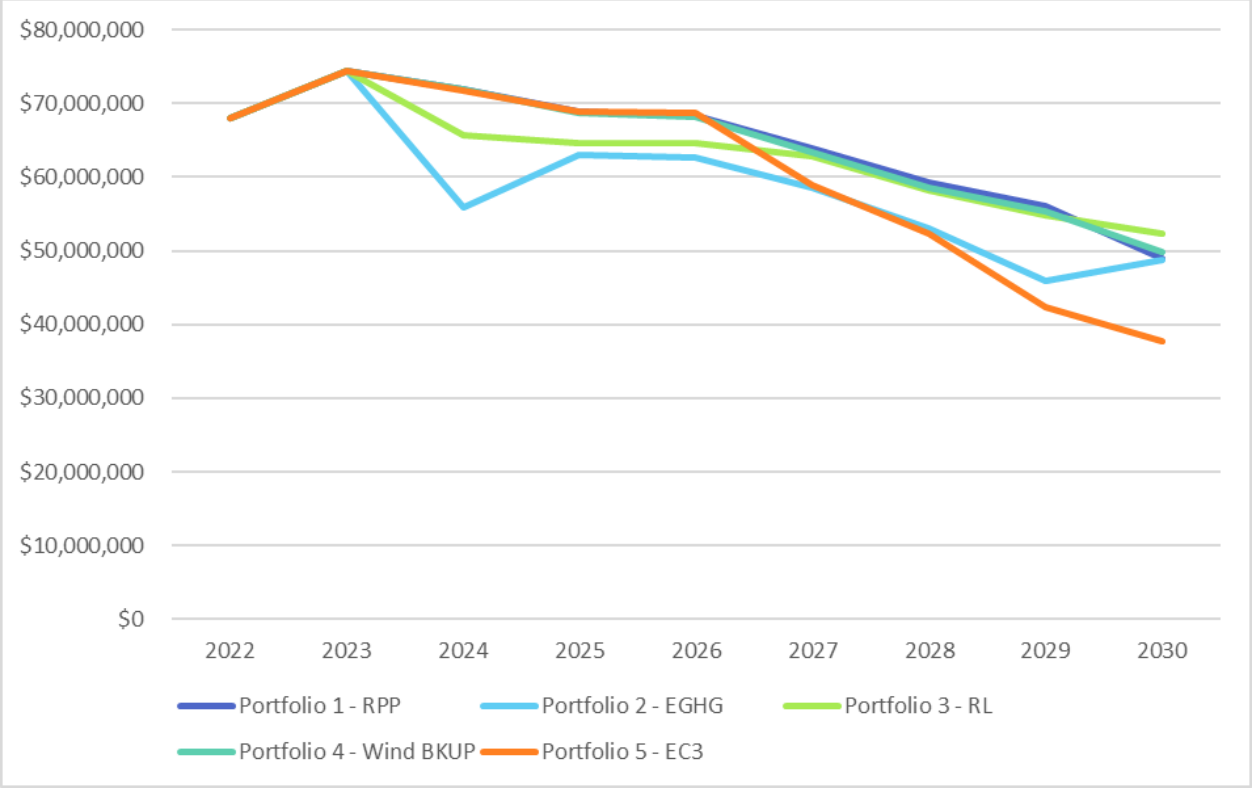


Figure 12: Comparison of SCoM



Financial Analysis

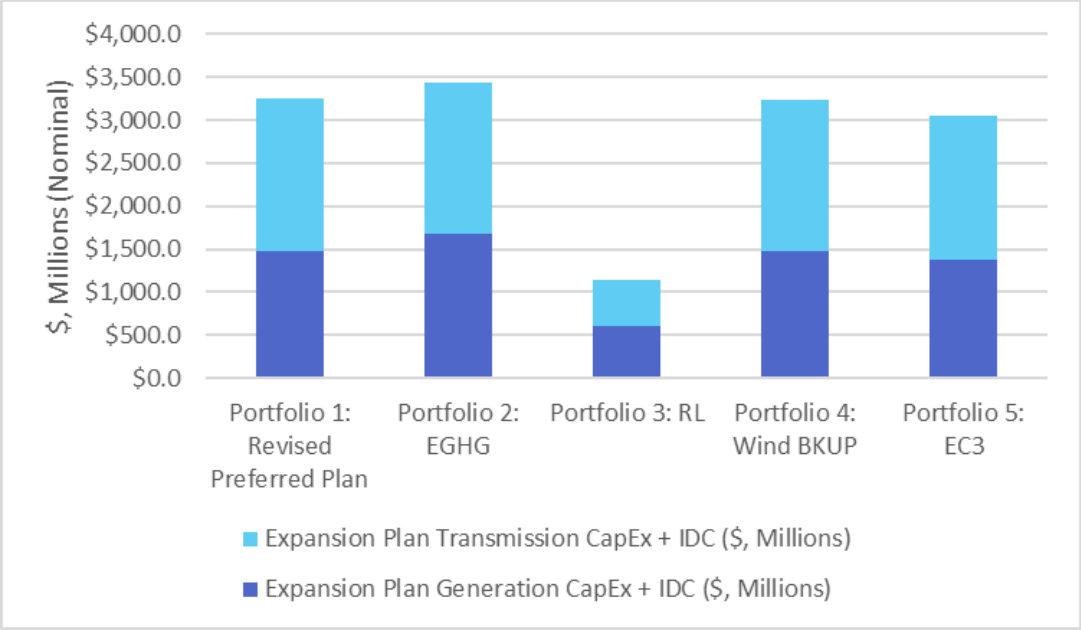
The following table compares total financial results for each portfolio, both with and without the SCoC and SCoM. Portfolio 1 (Revised Preferred Plan) is the lowest cost plan on a PVRR basis with the exception of the Portfolio 3 (Reduced Load) which requires fewer new resource acquisitions. Although Portfolio 1 (Revised Preferred Plan) has a higher PVRR when SCoC and SCoM are included, as compared to Portfolios 2 (EGHG) and 5 (EC3), these plans have a higher annual revenue requirement in the RAP, unacceptably increasing costs to Tri-State Members in the near-term. Portfolio 1 (Revised Preferred Plan) reaches Colorado GHG reduction targets, including significant reductions in SCoC and SCoM, while maintaining reliability and affordability—which best serves Tri-State Members' priorities.

Table 91: Comparison of PVRR

	PVRR ($, Millions)	PVRR w/SCoC and SCoM ($, Millions)
Portfolio 1: Revised Preferred Plan	$18,465.6	$30,125.5
Portfolio 2: EGHG	$18,576.8	$29,661.0
Portfolio 3: RL	$15,719.4	$27,883.7
Portfolio 4: Wind BKUP	$18,501.8	$30,277.5
Portfolio 5: EC3	$18,879.0	$29,265.5

The following figure compares capital expenditures and MW additions by portfolio.

Figure 13: Comparison of Generation and Transmission CapEx (Nominal $)



As shown in Table 92Table 95 below, the MW level and type of resource additions selected by the model were similar across Portfolios 1, 2, and 4. Portfolio 3 required few resource additions and significantly less transmission capital expenditure given the reduced load assumption. Portfolio 5 requires nearly

double the amount of resources to achieve the same levels of reliability over the RAP, than Portfolios 1, 2, and 4. Not only would Portfolio 5 result in undue near-term financial pressures for Tri-State Members, as discussed above, the technical feasibility of such resource additions is also questionable. The ability for Tri-State to acquire the forecasted amount of resources identified during the RAP for Portfolio 5 from experienced bidders at the size and locations needed, and, importantly, at a competitive and reasonable cost, is uncertain.

Table 92: Comparison of MW Additions by Portfolio, by Technology over the RAP

	Portfolio 1 – Revised Preferred Plan	Portfolio 2 – Early GHG	Portfolio 3 – RL	Portfolio 4 – Wind BKUP	Portfolio 5 – EC3
Wind	800	800	0	716	1,100
Solar	500	500	0	500	1,500
Battery Storage	125	125	0	125	350
Thermal	193	193	193	193	0
RAP Total	**1,618**	**1,618**	**193**	**1,534**	**2,950**

Table 93 below identifies the percentage of generation capacity and system energy that is renewable for each portfolio in 2030. Portfolio 1 (Revised Preferred Plan) yields the highest percentage of renewables in terms of generation capacity and system energy mix in 2030, except for Portfolio 5 (EC3) which is an outlier given the significant amount of resource additions it requires at a higher PVRR and with uncertainty in the technical and financial feasibility of such resource acquisitions, as described above, making it less comparable to the other portfolios.

Table 93: Comparison of Renewables' Contribution in 2030, by Portfolio

	2030 Generation Capacity Mix, % Renewables	2030 System Energy Mix, % Renewables
Portfolio 1: Revised Preferred Plan	57	68
Portfolio 2: EGHG	57	67
Portfolio 3: RL	48	54
Portfolio 4: Wind BKUP	56	65
Portfolio 5: EC3	61	77

Curtailments

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. The following table identifies the annual PPA curtailment costs (pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type. Significant curtailment costs in Portfolio 5 (EC3) represent the operational difficulty in integrating into the system a large amount of intermittent resources in a short timespan, while moving away from resources with dispatchable capability. The more measured approach to resource integration over time, taken in the other four portfolios, results in more reasonable curtailment impacts and supports greater affordability.

Table 94: Comparison of Wind PPA Curtailment Costs by Portfolio, Real (2022) $

	Portfolio 1 - Revised Preferred Plan	Portfolio 2 - Early GHG	Portfolio 3 - RL	Portfolio 4 – Wind BKUP	Portfolio 5 – EC3
2022	$0	$0	$0	$0	$0
2023	$0	$0	$0	$0	$0
2024	$0	$0	$0	$0	$0
2025	$0	$0	$2,603	$0	$0
2026	$0	$0	$1,671	$142	$0
2027	$0	$0	$0	$0	$24,255
2028	$3,348	$148,076	$0	$0	$474,847
2029	$46,512	$503,076	$0	$46,309	$3,151,858
2030	$1,727,512	$1,100,907	$0	$1,196,647	$7,102,829
RAP Total	**$1,777,373**	**$1,752,059**	**$4,274**	**$1,243,097**	**$10,753,789**

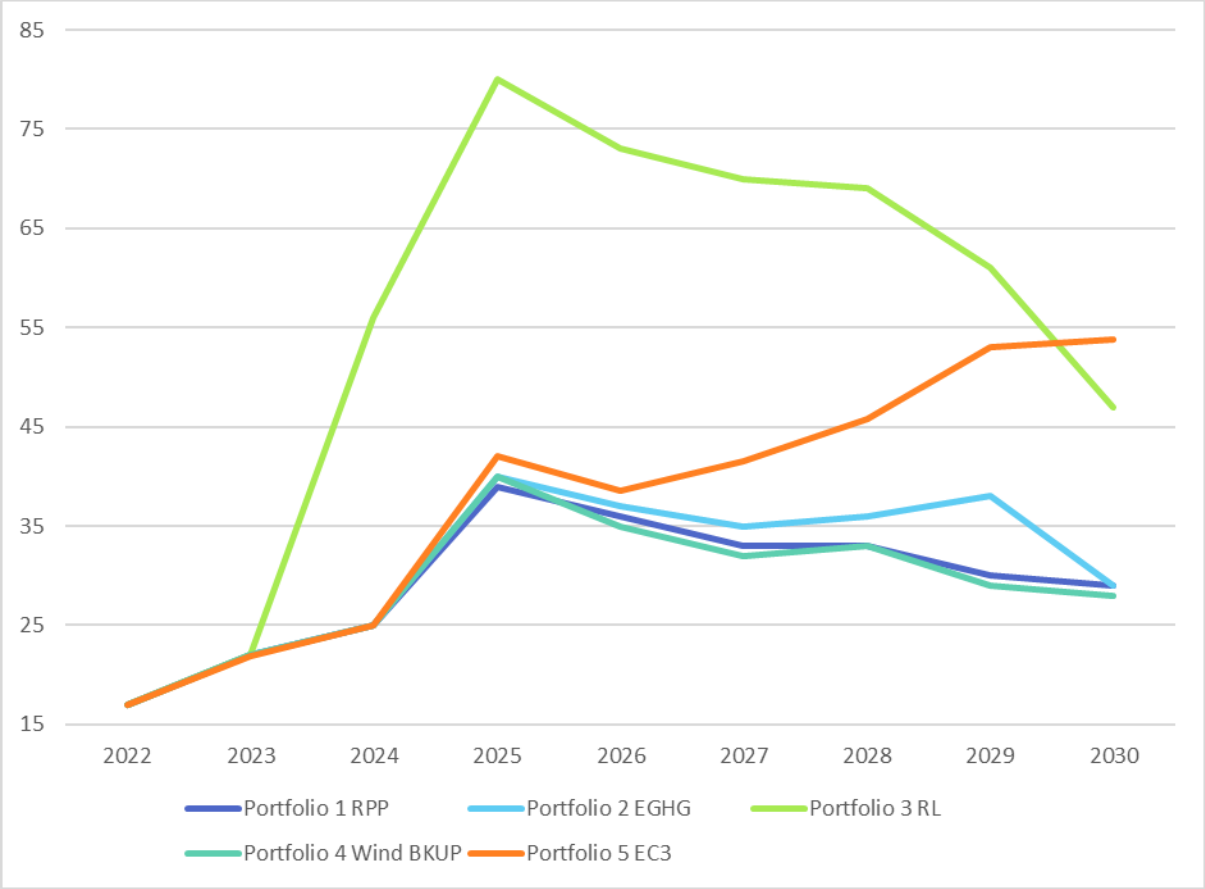
Table 95: Comparison of Solar PPA Curtailment Costs by Portfolio, Real (2022) $

	Portfolio 1 - Revised Preferred Plan	Portfolio 2 - Early GHG	Portfolio 3 - RL	Portfolio 4 – Wind BKUP	Portfolio 5 – EC3
2022	$0	$0	$0	$0	$0
2023	$0	$0	$0	$0	$0
2024	$0	$0	$0	$0	$0
2025	$11,490	$27,779	$25,576	$5,769	$18,286
2026	$26,572	$199,281	$30,680	$34,621	$96,989
2027	$64,948	$213,979	$23,600	$76,523	$923,683
2028	$75,517	$360,001	$34,157	$56,558	$6,389,605
2029	$234,197	$1,595,780	$66,264	$205,880	$26,096,716
2030	$2,933,914	$3,221,973	$14,903	$2,639,204	$27,121,912
RAP Total	**$3,346,638**	**$5,618,793**	**$195,181**	**$3,018,556**	**$60,647,191**

Reliability Analysis

PRMs were relatively consistent across three of the portfolios—Revised Preferred Plan, Early GHG, and Wind BKUP. The Reduced Load portfolio had considerably higher PRMs across the RAP than the other portfolios, given excess capacity becoming available due to a lower load requirement modeled. The EC3 portfolio also results in increasing PRMs after 2026 as a result of the large amount of intermittent resources modeled as new additions to the system during the RAP.

Figure 14: Comparison of PRMs During the RAP



Each of the portfolios were able to meet Level I and II reliability metrics. The Revised Preferred Plan is the portfolio that results in the greatest certainty in achieving reliability in the most cost-effective manner because it did not result from any forced modeling constraints that introduce risk.

The EC3 portfolio creates a forced early retirement of 448 MW of baseload generation and requires 950 MW of intermittent and semi-dispatchable resources to replace it in 2027, along with an additional 1,600 MW of intermittent resources to continue to maintain reliability from 2028 through 2030. The ability to swiftly integrate the extent of new resources suggested by EC3 modeling is uncertain, as described above. Further, in order to enable generation to reach load, additional third-party transmission capacity reservations had to be modeled for EC3 throughout the RPP, the use of which is not guaranteed to be available unless Tri-State could put a reservation in place before other interested parties. These factors associated with EC3 not only create financial burdens for Tri-State Members, but also result in resource adequacy concerns.

Conclusion

This Implementation Report provides extensive detail on the multiple portfolios modeled. We believe this analysis builds a clear record that supports approval of the Revised Preferred Plan portfolio. Tri-State requests the Commission find the Revised Preferred Plan portfolio to be a cost-effective resource plan and approve it in the Commission's Phase II Decision in this proceeding.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-87:
2025 Tri-State 2023 ERP 120 Day Implementation Report

Colorado PUC E-Filings System



Tri-State Generation and Transmission Association, Inc.

2023 Electric Resource Plan

Phase II Implementation Report

PUBLIC VERSION

(Colorado Public Utilities Commission Proceeding No. 23A-0585E)

NOTICE OF CONFIDENTIALITY

A portion of this document has been filed under seal.

Confidential Information has been redacted in the following documents.

- Report Pages 26, 27, 37, 38, 48, 49, 59, 69, 70, 80, 81
- Attachment B

Highly Confidential Information has been redacted in the following documents:

- Attachments B, B-4, B-7, B-8, C, C-1, D-1, D-2, D-3, D-4, D-5, D-6, F-1, F-2, F-3, G

April 11, 2025

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Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

This report is Tri-State's 2023 Electric Resource Plan (ERP) Phase II Implementation Report. The report complies with applicable Colorado Public Utilities Commission (CoPUC) Rules and Decisions as identified in Attachment A.

Tri-State's preferred portfolio is Portfolio 4 – New ERA Gas Flexibility Shafer Replacement (FLEXSR). The FLEXSR portfolio adds 700 MW of wind and solar, 650 MW of storage, and 307 MW of gas between 2026-2031, replaces the turbines at J.M. Shafer to improve its capacity contributions,[1] maintains the previously announced Craig 3 and SPV 3 retirement dates, and results in a generation portfolio that meets both Level 1 and Level 2 Reliability Metrics, the Colorado GHG emissions reduction targets,[2] the Colorado Renewable Energy Standard, and the New Mexico Renewable Portfolio Standard, all while avoiding costly transmission upgrades identified in other portfolios—making FLEXSR the least-cost portfolio.[3] This portfolio, which selects 1,657 MW of new resources from the 2024 Requests for Proposals (RFPs), reflects Tri-State Members' strategic directive to ensure reliable, affordable, and responsible service, and also addresses the CoPUC's recent concerns "…regarding the large, unexpected cost increases in transmission investments…" and a "need to improve [ ] transmission modelling and cost estimation processes in future ERP proceedings…"[4] The CoPUC Commissioners have also identified their concern in recent public meetings, recognizing that generation selected through ERPs has been "agnostic" in terms of evaluating associated transmission expenses and indicating a desire to "…analyze and optimize…options to ensure that our generation selection…to ensure that we're looking at optimizing costs across the system including the transmission system…"[5] Tri-State's approach to bid selections in the FLEXSR portfolio directly addresses these concerns, as described in detail in Attachment G.

Tri-State has selected the FLEXSR portfolio as a result of the portfolio's overall performance across the reliability, environmental, and financial categories analyzed and described in this report. Tri-State has taken steps to initiate a Resource Solicitation Cluster (RSC) for entering FLEXSR bids into Tri-State's Generator Interconnection through its Open Access Transmission Tariff (OATT) Large Generator

[1] The Shafer replacement is described in Attachment H.

[2] 2020 ERP Phase I Settlement Agreement, at Section 3.3.4 (Proceeding No. 20A-0528E): "Tri-State agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): A twenty-six percent (26%) reduction in calendar-year 2025; a thirty-six percent (36%) reduction in calendar-year 2026; and a forty-six percent (46%) reduction in calendar-year 2027."

[3] Lowest PVRR, exclusive of SCoC and SCoM.

[4] These concerns arose in other recent Phase II proceedings. *See* Decision No. C24-0052, at ¶ 158 in Proceeding No. 21A-0141E (issued January 23, 2024).

[5] CWM March 5, 2025, Commissioner Gilman at 1:12:31 and 1:12:53. Publicly available at: https://www.youtube.com/watch?v=dol_38ci5dU.

Interconnection Process. Four of the ten bids already have a queue position and therefore do not need to be part of the RSC study. The benefits of FLEXSR over other portfolios are reflected in the analyses presented in this Phase II report.

Portfolio Analysis Summary

Tri-State modeled six portfolios for Phase II of the 2023 ERP and created three back-up bid pools, as identified in Attachment B-3. All of the Phase II modeling reflected input assumptions based on the best available information available at the start of modeling, reflective of any known Tri-State system constraints and compliance requirements, as described in Attachment B and Attachments B-1 through B-8.

Tri-State remains in a capacity-long position until 2030;[6] however, resource acquisitions are required through this Phase II for ensuring ongoing resource adequacy and reliability as two coal units are retired in 2028 and 2031 and to maintain progress toward emission reductions for Colorado statutory compliance as well as for New ERA funding eligibility. Waiting to procure resources needed for 2030 until the 2027 ERP would not be prudent given that the 2027 ERP Phase II process may not conclude until late 2028 or early 2029; however, Tri-State is cautious to not pursue new resources based on speculative loads. At the same time, retirement of dispatchable coal resources cannot be affordably or reliably replaced solely with semi-dispatchable resources. The new resources, including the dispatchable gas plant in Moffat County, will provide jobs and tax base that support community vitality across many areas of our system.

Tri-State considered the Social Cost of Carbon (SCoC) and Social Cost of Methane (SCoM) when determining which Phase II portfolio was preferred, including analysis of the environmental and financial comparisons shown in the Comparative Analysis section of this report. Tri-State has taken these comparisons into significant account in determining that our preferred portfolio in Phase II is the best course of action at this time. Tri-State's preferred portfolio achieves the lowest present value of revenue requirements (PVRR), meeting the affordability expectations of Tri-State Members in avoiding the risks associated with procuring bids selected in other portfolios at a higher cost that do not yield impactful environmental or reliability attributes.

All of the Phase II portfolios meet essential reliability targets, while achieving an 80 percent GHG emissions reduction in Colorado in 2030 (with respect to the 2005 baseline)[7] reflective of Colorado policy.[8] However, the other portfolios analyzed result in significant, unnecessary financial burdens by aggressively pursuing resources with high transmission interconnection upgrade costs that are not necessary to achieve the same operational, environmental, and reliability benefits resulting from procurement of FLEXSR bids. Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data indicates 59 percent of our service area is considered economically disadvantaged or distressed.[9] Tri-State is not in a position to pursue generation procurements that

[6] *See* Table 2, Loads and Resources, submitted in the 2024 ERP Annual Progress Report filed December 2,2024 in Proceeding No. 23A-0585E.
[7] See Attachment D.
[8] §25-7-105(1)(e)(VIII)(I), C.R.S.
[9] U.S.D.A.: https://ruraldevelopment.maps.arcgis.com/apps/webappviewer/index.html.

would cause significant undue financial burdens for Members[10] or compromise its ability to meet the core reliability expectations of its Members.

Additional details on the comparative analysis Tri-State completed to support its preferred portfolio selection can be found in the Comparative Analysis section of this report.

Addressing Commission Rule 3605(h)(II)

The Commission must consider the following factors in issuing a Phase II decision:

> *In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.*

Phase II of Tri-State's 2023 ERP included RFPs for a diverse mix of renewable, storage, and dispatchable resources located across the Tri-State system. Bidders were required to provide Best Value Employment Metrics (BVEM) information identifying Colorado employment benefits.[11] The Phase II portfolio analysis reflected GHG Targets (2025, 2026, 2027, and 2030),[12] Energy Efficiency Targets (2024, 2025, and 2030),[13] and Demand Response Targets (2025 and 2030)[14] as agreed upon in the Settlement Agreements in Phase I of the 2020 and 2023 ERPs.

Colorado's energy security, economic prosperity, and insulation from fuel price increases are best supported by a Tri-State portfolio that is diverse in the type, size, location, and operations of generation, including through bid procurements that avoid costly transmission network upgrades. Tri-State developed, in consultation with stakeholders, a set of robust reliability criteria in 2022, updated reflective of a third-party 2024 EWE Study, and tested portfolios' extreme weather event (EWE) sensitivities to ensure future resource additions can meet the necessary reliability and resource adequacy needs of its Members. The FLEXSR preferred portfolio meets these rigorous standards, both affordably and responsibly.

The preferred portfolio will continue to advance the environmental objectives of the State of Colorado because it is forecasted to achieve the Colorado GHG Targets. The GHG reductions were calculated using the Colorado Air Pollution Control District's (APCD) emissions workbook methodology.

[10] Tri-State is subject to Federal Energy Regulatory Commission rate jurisdiction, as of September 3, 2019.
[11] *See* HIGHLY CONFIDENTIAL Attachment F-1.
[12] 2020 ERP Settlement Agreement, at Section 3.3.4. (Proceeding No. 20A-0528E).
[13] 2020 ERP Settlement Agreement, at Section 3.11.9. (Proceeding No. 20A-0528E).
[14] 2020 ERP Settlement Agreement, at Section 3.11.8. (Proceeding No. 20A-0528E); 2023 ERP Settlement Agreement, at Section 4.9.1. (Proceeding No. 23A-0585E).

In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.

Tri-State has provided BVEM provided by bidders, for the bids advanced to modeling, in HIGHLY CONFIDENTIAL Attachment F-1.

Tri-State included evaluation of BVEM as a non-price factor in its bid evaluation, as described in the Bid Evaluation section of this report.

Tri-State intends to enter into power purchase agreements (PPAs) and Engineering, Procurement, and Construction contracts (EPCs) for the preferred portfolio generation and storage facilities; therefore, the developers and EPC contractors will be responsible for determining whether a project labor agreement will be used.

In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.

The FLEXSR preferred portfolio is the most cost-effective portfolio modeled, having the lowest PVRR. The preferred portfolio also complies with all applicable rules and regulations in the state of Colorado, including achieving at least an 80 percent reduction in GHG emissions by 2030 while continuing to ensure affordable and reliable service.

In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.

The FLEXSR preferred portfolio has the lowest PVRR among the portfolios modeled, including analysis for optimization of interconnection cost as described in Attachment G. Tri-State considered the SCoC in its review of the portfolio modeling results as described in the Portfolio Analysis Summary section above and in the Comparative Analysis section below.

Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in stakeholder engagement throughout the 2023 ERP. Numerous stakeholder groups representing a diverse set of interests participated in meetings in advance of Tri-State's filing of this Implementation Report. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform parties of key modeling inputs and assumptions, and facilitate dialogue on topics applicable to Phase II. These stakeholder meetings occurred between December 2023 and March 2025, covering the following topics:

1. November 29, 2023: Briefing on 2023 ERP Phase I Filing

2. January 24, 2024: EWE Focus Group[15] Meeting #1
3. March 1, 2024: EWE Focus Group Meeting #2
4. March 21, 2024: EWE Focus Group Meeting #3
5. April 23, 2024: 2024 DSM Roundtable Meeting (1 of 2)
6. June 11, 2024: FERC Filing Updates
7. September 24, 2024: Meeting on USDA Guidance and Phase II Portfolios[16]
8. October 30, 2024: Meeting on EWE[17]
9. December 10, 2024: 2024 DSM Roundtable Meeting (2 of 2)
10. December 23, 2024: Colorado PUC Staff Meeting on MIP[18]

Several e-mail communications and updates to stakeholders also occurred in advance of and during Phase II modeling with the aim of ensuring communications on key Phase II topics. Tri-State maintains ongoing collaboration with interested stakeholders across a variety of electric sector topics.

Bid Evaluation

Tri-State issued three Phase II RFPs on September 13, 2024. Tri-State's bid evaluation process was undertaken over a 45-day period following the close of the RFPs on October 28, 2024.[19] The bid evaluation process, completed prior to advancing projects to Phase II computer-based modeling, consisted of several steps – including a completeness screen, an economic screen, an interconnection/transmission screen, and a non-price factor screen.

The ***completeness review*** included an assessment of whether bids provided required information, such as fully completed bid forms or other narrative requirements. This screen also ensured submittal of the required bid fee(s). When bid information appeared incomplete or unclear, Tri-State contacted the bidders and provided them approximately two business days to supplement their bids with the necessary information to enable the bids to move forward in the bid evaluation process.

Following the completeness review, bids were sorted by technology type (wind, solar, etc.) and passed through an ***economic screen***. Either a levelized cost of energy (LCoE) or leveled cost of capacity (LCoC) was evaluated, depending on the technology type, as identified in the table below.

Table 1: Economic Screen by Technology Group Applied to Phase II Bids

LCoE	LCoC
Solar	Standalone Battery
Wind	Dispatchable Combustion Turbine
Solar + Battery	Dispatchable Natural Gas with CCS
Wind + Battery	
Geothermal	

[15] EWE Focus Group included Tri-State, Tri-State's Wyoming Members, Grid Lab, Sierra Club and their consultants, and Rocky Mountain Institute (RMI).
[16] 2023 ERP Settlement Agreement, at Section 4.4.3 (Proceeding No. 23A-0585E).
[17] 2023 ERP Settlement Agreement, at Section 4.8.3 (Proceeding No. 23A-0585E).
[18] 2023 ERP Settlement Agreement, at Section 4.4.8 (Proceeding No. 23A-0585E).
[19] The dispatchable RFP bid deadline was extended to November 27, 2024 due to the limited number of bids received.

Bids in each technology group, in various size ranges, were advanced to the transmission and interconnection screen if the costs were at or below the latest generic resource pricing and/or where other size, locational, or diversity considerations were applied.

The ***interconnection/transmission screen*** included a review of project/facility sizes (capacity), point of interconnection (POI), transmission provider, and queue status and transmission/interconnection provider verification. Bidders were expected to clearly identify projected interconnection and transmission costs in their proposals as well as reflect these costs in the prices associated with each bid. Tri-State's Transmission Planning team reviewed each bid's viability and the reasonableness of associated cost estimates. The viability screen focused on the ability of the transmission system to accommodate the new firm resource and the ability to construct the project, including network upgrades and interconnection facilities by the identified in-service date. Cost estimates were reviewed to ensure bids factored in a reasonable level of network upgrade and interconnection facility costs to integrate the project at the identified point of interconnection. Finally, Tri-State's Transmission Planning team verified whether the project was in an interconnection queue based on the information provided by the bidder. For projects achieving commercial operation in 2026 or 2027, bidders were required to be in an interconnection queue under a transmission provider's generator interconnection process. For those projects whose commercial operation dates (COD) were anticipated to be after 2027, bidders were encouraged to be in an interconnection queue, however, this will not be a requirement in the interconnection/transmission screen.

For projects under a PPA structure, interconnection with the Tri-State transmission system was viewed more favorably than those projects connecting to a third-party transmission system. For projects in which Tri-State was seeking ownership, interconnection with the Tri-State transmission system was required. The interconnection/transmission provider was noted as part of the interconnection/transmission screen.

Projects that did not receive favorable evaluation results during the interconnection/transmission screen were eliminated from further consideration in the bid evaluation process. In cases where the interconnection/transmission screen identified certain flawed aspects of an otherwise viable bid, related primarily to cost and/or in service date assumptions, Tri-State contacted bidders for clarification and cost updates.

Lastly, Tri-State conducted a ***non-price factor analysis*** of the bids that emerged from the interconnection and transmission screen. The non-price factor analysis considered project capabilities across four categories: community stewardship, counterparty profile, project feasibility, and project capability. The factors are identified in the table below.

Table 2: Non-Price Factors

Category	Factor
Community Stewardship	• Best Value Employment Metrics • Contribution to meeting GHG reductions in Colorado • Location in a Tri-State Member System • Location in Moffat County or West End of Montrose County • Community Benefits
Counterparty Profile	• Bidder's prior experience with project development

	• Bidder's record of litigation related to power supply agreements and failure to honor bids from prior solicitations, or failure to complete projects as proposed • Financial viability of the bidder • Markup of PPA or term sheet terms and conditions
Project Feasibility	• Certainty of financing and outside funding sources to include tax credits or government subsidies/incentives • Compliance with all applicable local, state and federal laws, rules and orders, and processes; permit(s) identification and status • Local opposition or community efforts to stop project development • Ability to source materials • Project retirement/decommissioning plan • Legal, engineering and other costs required to implement the proposed project
Project Capability	• Renewal and purchase options at end of PPA (if applicable) • Impact on scheduling project output to Tri-State load • Operational flexibility

Projects with overall favorable non-price factor analysis were advanced to modeling; however, poor evaluation results in certain non-price factor categories resulted in a project not being advanced to modeling.

Bids Received

Tri-State received 145 individual eligible bid proposals by the bid deadline, as identified in the 45-Day Report filed in Proceeding No. 23A-0585E on December 12, 2024. A total of 52 bids were advanced to modeling, as shown in HIGHLY CONFIDENTIAL Attachment C, following the bid evaluation described above. On December 5, 2024, Tri-State notified bidders whether their projects had advanced to modeling and offered a price refresh opportunity per Tri-State's Bid Policy,[20] due December 9, 2024. For bids not advanced to computer-based modeling, and for which bidders requested additional feedback on their bids, Tri-State identified at which stage of the bid evaluation process the bid failed to pass a screen and offered an opportunity for further discussion at or near the conclusion of Phase II. Tri-State also provided details in its 45-Day Report[21] identifying how many bids failed to pass each screen and factors that caused bids to fail at each screen.

Table 3: Summary of Bids Advanced to Modeling by Technology Type

Technology Type	Total (# of Bids)	MW	MW BESS
Solar	12	2,303	-
Wind	6	1,218	-
Solar+Battery	12	2,049	907
Wind+Battery	1	180	100
Short-Duration Storage	16	-	2,200

[20] Hearing Exhibit 102 Attachment SKH-7 (Proceeding No. 23A-0585E).

[21] https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1032592&p_session_id=

Long-Duration Storage	1	-	100
Gas Plant	2	495	-
Gas Tolling	1	314	-
Geothermal	1	20	-
TOTAL	**52**	**6,579**	**3,307**

Commission Rule 3605(h)(I)(A)(iii) requires that Tri-State "provide the Commission with the best value employment metrics information provided by bidders." The BVEM information provided by bidders whose bids were advanced to modeling is provided in Attachment F-1. As identified in Table 2 above, BVEM is a non-price factor analyzed by Tri-State as an element of bids' community stewardship.

Tri-State is also providing to the Commission and stakeholders a mapping of the bid project locations overlayed with a map of disproportionately impacted (DI) communities, in Highly Confidential Attachment C-1.[22] The file contains five maps: 1) all bids with DI overlay, 2) bids advanced to modeling with DI overlay, 3) bids selected in portfolio modeling with DI overlay, 4) bids selected in the preferred portfolio with DI overlay, and 5) bids selected in the preferred portfolio with Tri-State Member territories overlay.

Bids Selected in Portfolio Modeling

Table 4 identifies the bids selected in one or more of the portfolios modeled.

Table 4: Bids Selected in Portfolio Modeling

Bid	Technology Type	MW	Portfolios					
			1 – NEE	2 – NELG	3 – FLEX	4 – FLEXSR	5 – NNG	6 – NNGSR
PV-0004-4-nm	Solar	100	☒	☒	☒		☒	
PV-0004-5-wco	Solar	140	☒	☒			☒	
PV-0006-8-eco	Solar	200				☒		☒
WI-0013-2-wyo-wne	Wind	200	☒	☒	☒	☒	☒	☒
WI-0013-3-eco	Wind	200	☒	☒		☒	☒	☒
WI-0016-1-eco	Wind	297			☒			
PC-0009-2P-eco	Solar / Battery	150 / 75	☒	☒	☒		☒	
PC-0018-1P-nm	Solar / Battery	100 / 50	☒	☒	☒	☒	☒	☒
ST-0002-5-wco	4hr - Battery	50	☒	☒	☒	☒	☒	☒
ST-0002-6-wco	4hr - Battery	100		☒				
ST-0004-10-eco	4hr - Battery	100		☒		☒	☒	☒
ST-0004-6-eco	4hr - Battery	150				☒		☒
ST-0004-8-wco	4hr - Battery	200					☒	☒
ST-0004-9-eco	4hr - Battery	100					☒	☒
ST-0009-3-wco	4hr - Battery	200	☒	☒	☒	☒	☒	☒
ST-0009-4-nm	4hr - Battery	100	☒	☒	☒	☒	☒	☒
ST-0010-4-eco	4hr - Battery	150			☒		☒	☒
ST-0017-1-eco	4hr - Battery	100	☒	☒	☒		☒	☒
ST-0018-1-eco	4hr - Battery	50			☒		☒	
ST-0019-1-eco	Iron Air Battery	100	☒				☒	

[22] 2023 ERP Settlement Agreement, at Section 4.10.2. (Proceeding No. 23A-0585E).

GG-0006-1-wco	Combustion Turbine	307		☒				
GG-0006-2-wco	Combustion Turbine[23]	307	☒		☒	☒		

Independent Evaluator

Tri-State utilized the services of a third-party Independent Evaluator (IE) to support RFP administration, and to validate the bid evaluation process and results. The role of the IE was to ensure fairness, transparency, and consistency in Tri-State treatment of bids.

In order to provide the bidder a paperless (electronic only) experience and prior to the Phase II RFP release, the IE assisted Tri-State with web hosting, website development, and web-form development to provide a standardized bidder experience by hosting the following services: RFP website and bidder registration, notice of intent and non-disclosure agreements process support, and bidder document upload and storage management. Tri-State created an Outlook mailbox for each RFP that the IE could also access, enabling the IE to view communications with bidders, to monitor for consistency and transparency.

The IE reviewed the non-price factor evaluation criteria matrix prepared by Tri-State and confirmed its fairness and consistency and alignment to the Bid Policy. After Tri-State completed each bid evaluation screening phase, Tri-State prepared a summary of the results that included the purpose of the screen, the evaluation criteria, and the bid advancement results; then Tri-State and the IE discussed the results. The IE independently reviewed a subset of bids that passed and failed each screen to validate and ensure consistency across bid evaluation results. The IE communicated its completion of each screening review.

Due to only a very limited number of bids being received on October 28, 2024, in response to the Dispatchable RFP, Tri-State consulted with the IE for concurrence in issuing a 30-day extension for the Dispatchable RFP to November 27, 2024. Tri-State informed the 2023 ERP Settling Parties of the Dispatchable RFP extension via email. Beginning November 28, 2024, Tri-State and the IE completed an accelerated screening of dispatchable bids to remain on track with the 45-day bid evaluation period.

The IE uses and is familiar with EnCompass, the same modeling software used by Tri-State. Tri-State shared its model with the IE for review of Tri-State's modeling inputs and set-up, primarily for ensuring bid data was consistent with bidder-provided information. After Phase II portfolio modeling, the IE also reviewed modeling outputs for any anomalies.

The IE is expected to file a report providing its observations of Tri-State's Phase II process simultaneous to the filing of this report.

Phase II Portfolio Analysis

Tri-State modeled six portfolios:

1. New ERA Expanded (NEE)
2. New ERA Limited Gas (NELG)

[23] Eight 38.36 MW natural gas-fired turbines, hydrogen-capable with a demonstrated blend of 30%.

3. New ERA Gas Flexibility (FLEX)
4. FLEX Shafer Replacement (FLEXSR)
5. No New Gas (NNG)
6. NNG Shafer Replacement (NNGSR)

The modeling assumptions unique to each portfolio are identified in Attachment B-3.

Tri-State also conducted expansion plan modeling to identify three back-up bid pools:

7. Renewable Back-up Bid Pool (BkRE)
8. Standalone Storage Back-up Bid Pool (BkST)
9. Gas Plant Back-up Bid Pool (BkNG)

Tri-State will, to the extent necessary, utilize backup bid pools to replace preferred plan bids that fail. If a preferred plan bid cannot move forward, Tri-State aims to replace it with a similarly sized, similar technology type project, if possible, subject to limitations and economics. This designation of bids as back-ups is limited to creation of a potential pool of the next most economic bids, as Tri-State cannot anticipate which preferred plan bid or subset of bids could fail at a given point in time; therefore, modeling unknown and possible portfolio permutations would be inefficient. The bids identified in the back-up pools are not listed in an anticipated order of preference; this is because selection from the back-up pools depends upon which preferred plan bid would happen to fail and what location of the Tri-State system that bid was located and the transmission constraints projected at the bid locations at the time of CODs. Tri-State would, upon any bid failure(s), utilize bid(s)[24] from the relevant back-up bid pool along with the remaining preferred portfolio of bids still viable, and run a dispatch at that time to ensure continued adherence to the same affordability, reliability, and responsibility metrics and principles each Phase II portfolio was measured against. Tri-State will timely notify the Commission of any bid failures, identify steps taken to remediate the failed project, where feasible, and identify the back-up bid, or combination of backup bids, selected from the pools.

Additionally, a sensitivity analysis was performed to re-dispatch each portfolio under EWE conditions. The modeling assumptions and results of the sensitivity analyses are provided separately in Attachment E.[25]

Each section of this report that follows presents data and analytical results from base portfolio modeling, formatted in the following order:

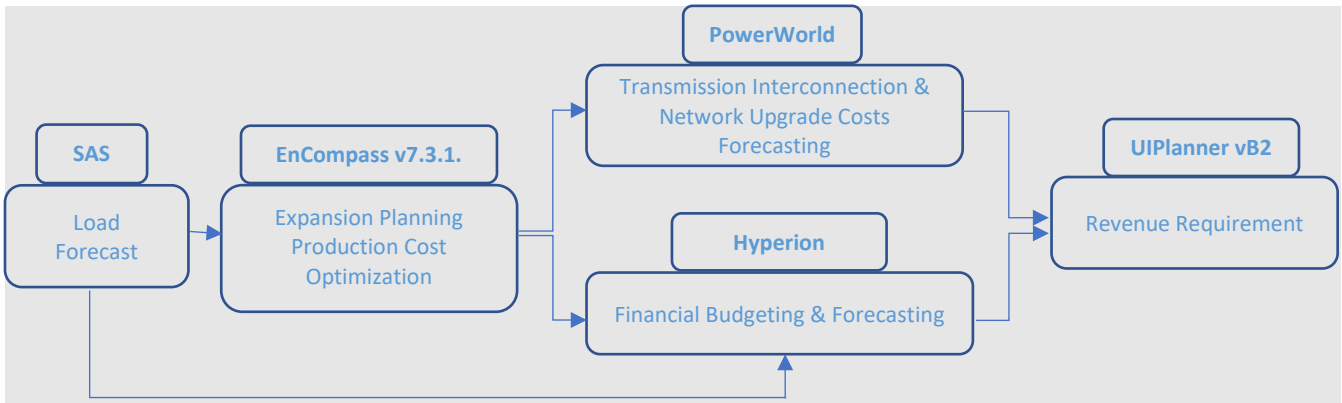
- Expansion Plan, Retirements, System Mix, and Capacity Factors
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

An overview of Tri-State's approach to each element of the portfolio analyses is provided below.

[24] One bid, depending on the unit size, may need to be replaced by one or more bids.
[25] 2023 ERP Settlement Agreement at Section 4.8.1. (Proceeding No. 23A-0585E).

Figure 1 below identifies the software tools utilized by Tri-State for completing each component of the portfolio analyses and the succession of data flow through each modeling and analytical system. Use of the EnCompass modeling software for capacity expansion and portfolio optimization began in 2022.

Figure 1: Modeling Software Tools



Expansion Plan, Retirements, System Mix, and Capacity Factors

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase II modeling, inputting the applicable modeling assumptions described in Attachment B and Attachments B-1 through B-8, as applicable. Resource bids advanced to modeling as a result of the RFPs issued by Tri-State on September 13, 2024 and selected in the portfolio expansion plans are identified by a bid identifier, resource type, and project megawatts (MW).

The RAP for Phase II is 2026-2031, with the full Resource Planning Period (RPP) modeled for 2024-2043.[26]

Environmental Analyses

Based on the expansion plan and dispatch produced for each portfolio, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon and methane.

For each portfolio, Tri-State separately produced a verification workbook, using the Colorado Air Pollution Control Division's (APCD) latest template,[27] calculating forecasted carbon emissions reductions, provided in Attachment D files. Target-year emissions reductions percentages for each portfolio, calculated within the verification workbooks, are provided in this report.

Financial Analyses

Pursuant to Rule 3605(h)(I)(A)(ii), Tri-State provided a financial analysis of each portfolio and each Tri-State owned resource, including:

- Annual revenue requirements;

[26] Tri-State's Hyperion financial forecasting for 2024 consists of six months of actuals and six months of forecast. Tri-State's financial forecasting for 2025 reflects Tri-State's Budget rather than EnCompass 2023 ERP Phase II dispatch output due to timing of the modeling, however, neither year is part of the Resource Acquisition Period (RAP).

[27] *See* Attachment B.

- Present value revenue requirement, with and without the social costs of carbon and methane; and
- A net present value of each owned resource, over the planning period, with and without the social costs of carbon and methane.

Additionally, one of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order.[28] For each portfolio, curtailment MWhs by intermittent resource type seasonally and year are provided.

Transmission Analyses

Bidder-provided transmission cost estimates for proposed generation projects submitted in response to Tri-State's RFP were analyzed as part of the bid evaluation process to identify bids that should be advanced to portfolio modeling. Each portfolio was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades.

In addition to the traditional transmission interconnection and upgrades estimates prepared for each portfolio, Tri-State evaluated preferred portfolio bid selection in a manner that optimized interconnection costs, given growing transmission system constraints in recent years. As Tri-State was completing 2023 ERP Phase II portfolio modeling, it became increasingly clear that the EnCompass model was effectively selecting least-cost bids based on their operational profiles and the Tri-State system needs and transmission constraints, but the expansion plan model did not have full insight into the downstream transmission interconnection and network upgrade costs that were resulting from the bid selections. Additionally, the model could not identify opportunities where use of surplus interconnection could maximize the value of existing interconnections.[29] Tri-State was able to complete interconnection optimization for two of the portfolios—the preferred portfolio (FLEXSR) and the NNGSR portfolio. Optimizing the preferred portfolio enabled the avoidance of approximately $370M in transmission capital expenditures inclusive of allowance for funds used during construction (AFUDC) during the RAP. Optimizing the NNGSR portfolio enabled the avoidance of approximately $317M in transmission capital expenditures including AFUDC during the RAP.

Transmission planning cannot at this time be fully integrated into the generation planning process due to regulatory jurisdiction and organized market considerations, unique transmission and generation planning compliance requirements, bid timeline constraints, and variations in key modeling input cycles. However, Tri-State was able to address interconnection optimization in this Phase II by separately evaluating transmission cost and locational aspects of the bids following expansion plan selection. Going forward, Tri-State will integrate this optimization step across all portfolios beginning in Phase II of

[28] In the event that resources must be curtailed, Tri-State's model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic minimum and must take contracts (*i.e.,* hydropower and Basin contracts)–in that order.

[29] A recent report from GridLab suggests "PUCs should require evaluation of surplus interconnection options in integrated resource planning (IRP)," See *Existing Power Plants Sharing Grid Access with Renewables Can Lower Costs and Double U.S. Generation Capacity*, at page 4, released in February 2025: https://surplusinterconnection.s3.us-east-1.amazonaws.com/2025-02-21_GridLab_Surplus_Interconnection_Technical_Paper.pdf.

the 2027 ERP, to continue to enable the avoidance of interconnection and upgrade expenses and optimize use of the existing transmission system. Tri-State will work with its EnCompass software provider, and the IE, to identify potential approaches to informing the model of bid interconnection costs and transmission upgrade costs within the expansion plan selections, and will describe any proposed modeling changes in its Phase I filing for the 2027 ERP.

Reliability Analyses

Level 1 reliability metric checks were performed on each portfolio for all years of the RPP,[30] including:

- *Planning Reserve Margin (PRM):* Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%).[31]
    - Target (min) is 22% transitioning to 30.5% in 2028 after the retirement of the Craig facility
- *Loss of Load Hours (LoLH)*[32]: Measure of the likelihood of failing to meet system load (hours per 10 years).
    - Target (max) is 1 day in 10 years (99.973% reliability)[33]
        - 2024-2031 – annually cannot exceed 2.4 hours[34]
        - 2032-2043 – cannot exceed 24 hours over entire period
- *Expected Unserved Energy (EUE)*[35]: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
    - Targets (max):
        - ≤ 0.4 GWh annually[36]

Evaluation of Level 2 Reliability Metrics, identified in Attachment B-5, was performed on each portfolio's EWE dispatch for all years of the RPP,[37] with results reflected in Attachment E.

Comparative Analysis

Tri-State compared and analyzed results across portfolios, which can be found in the Comparative Analysis section of this report.

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[30] 2023 ERP Settlement Agreement, at Section 4.8.2. (Proceeding No. 23A-0585E).

[31] *Reserve Margin and Effective Load Carrying Capability (ELCC) Study,* Astrape Consulting, publicly available here: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1011579&p_session_id=

[32] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2023 ERP Phase I.

[33] Splitting the LOLH target over the planning period reflects Tri-State's desire to have added assurance that intra-year reliability in the near-term is met by resources coming online during the RAP as the generation fleet makes significant transitions through this period. This approach also allows Tri-State to cautiously assess the impact of having an increasing percentage of intermittent resources in its fleet and the uncertain potential for more severe EWEs before applying similarly stringent LOLH metrics to the outer years of the planning period. There is more flexibility allowed in the out years as forecasting and technology uncertainty is greater during this period.

[34] The annual LOLH target of 2.4 hours is an equivalent representation of the 1 day in 10 years reliability standard.

[35] EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.

[36] This metric is aimed at limiting EUE to a reasonable level below the historical annual average, consistent with the 2023 ERP Phase I.

[37] 2023 ERP Settlement Agreement, at Section 4.8.2. (Proceeding No. 23A-0585E).

State Renewable Policy Compliance Analysis

Tri-State reviewed the results of each portfolio and affirms that all portfolios meet or exceed the minimum applicable state renewable energy standard (RES) or renewable portfolio standard (RPS) requirements. RES/RPS standards are shown in the following table.

Table 5: Colorado RES and New Mexico RPS Requirements during RPP

	Colorado RES[38, 39]		New Mexico RPS[40]
	Co-ops	**Tri-State**	**Co-ops**
2024	10%	20%	10%
2025-2029	10%	20%	40%
2030-2050	10%	20%	50%

[38] § 40-2-124(1)(c)(I)(D) and (c)(V)(D), C.R.S.
[39] § 40-2-124(8)(b), C.R.S.
[40] N.M. Stat. Ann. § 62-15-34.

1. New ERA Expanded (NEE)

Assumptions unique to the New ERA Expanded (NEE) portfolio are identified in Attachment B-3.

Portfolio 1 (NEE) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 6: Expansion Plan (Portfolio 1 – NEE)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[41]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
2028	ST-0019-1-eco	Iron Air Battery	East Colorado	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
2033	-	Wind / Battery	New Mexico	100	2	200
2035	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	New Mexico	100	1	100
	-	10hr - Battery	East Colorado	100	1	100
2037	-	Wind / Battery	Wyoming / W.Neb	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	New Mexico	100	1	100
2042	-	Solar	New Mexico	100	1	100
	-	Wind	East Colorado	100	3	300
2043	-	10hr - Battery	East Colorado	100	1	100
	-	Wind	East Colorado	100	1	100

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency was selected in the expansion plan of Portfolio 1 – NEE.
- 2030: Low Wyoming Energy Efficiency was selected in the expansion plan of Portfolio 1 – NEE.

[41] Each bid is modeled as a single project for purposes of expansion plan selection.

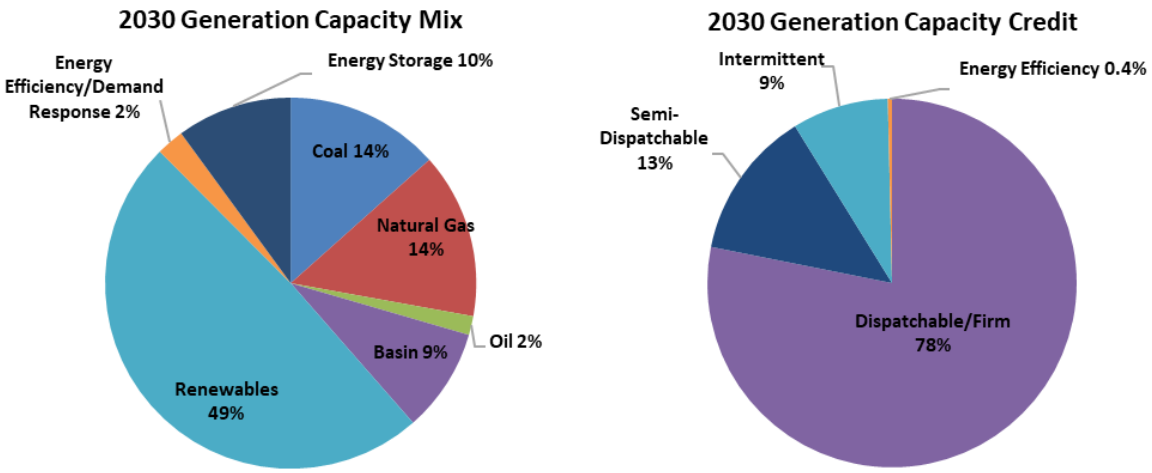
Unit retirements, scheduled or selected in the modeling, are shown in the following table.[42]

Table 7: Modeled Retirements (Portfolio 1 - NEE)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[43]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 2: Projected Tri-State System Capacity Mix 2030 (Portfolio 1 – NEE)[44, 45]



[42] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and its share of Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[43] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement by USDA to disperse all New ERA funds by September 30, 2031.

[44] "Renewables" category reflects wind and solar PPAs, Member Distributed Generation (DG), energy associated with renewable energy credits (RECs) received via the Basin contract, and hydropower purchases.

[45] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 3: Projected Tri-State System Energy Mix 2030 (Portfolio 1 – NEE)[46]

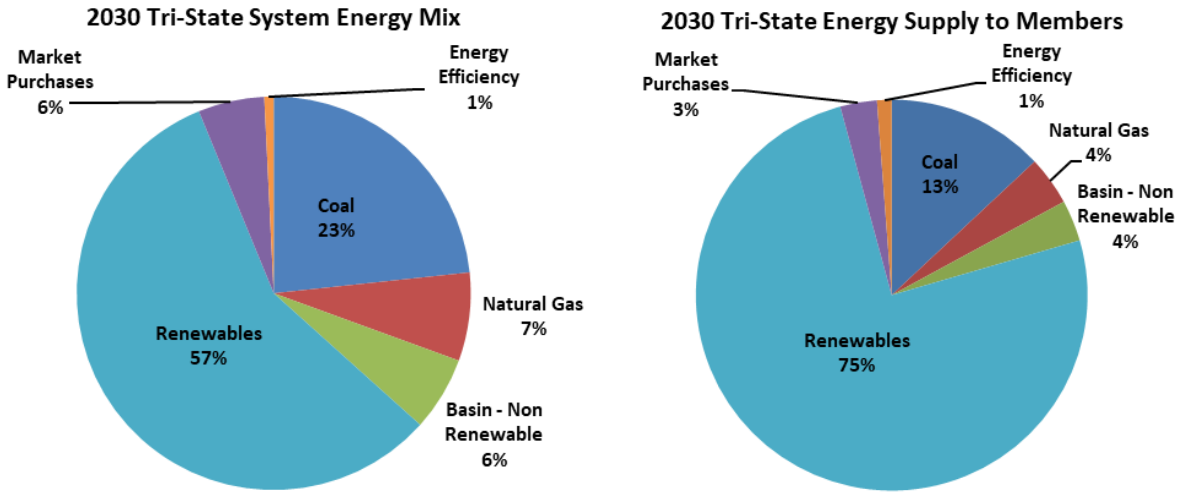


Table 8: Projected Annual Capacity Factors for Thermal Resources (Portfolio 1 – NEE)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	68%	84%	65%	73%	83%	82%	80%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	5%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	0%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	26%	19%	24%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 1 (New ERA Expanded) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[46] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 9: Environmental Impact - System Wide (Portfolio 1 – NEE) [47]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,962,306	6,093	7,512	0.0335	975	4,183,354,305	24,235
2027	11,750,117	5,940	7,360	0.0327	961	4,161,589,886	23,953
2028	9,874,804	5,208	6,125	0.0290	841	3,480,893,766	20,201
2029	9,043,741	7,796	6,571	0.0268	729	3,080,720,212	17,940
2030	7,345,275	10,258	6,986	0.0238	607	2,691,211,959	16,047
2031	6,399,384	9,943	6,815	0.0207	370	2,139,654,056	13,265
2032	5,656,566	9,627	6,510	0.0177	259	1,784,885,467	11,492
2033	5,818,338	9,697	6,570	0.0187	278	1,863,239,379	11,783
2034	5,682,522	9,640	6,485	0.0181	274	1,803,058,523	11,491
2035	5,813,155	9,712	6,584	0.0187	273	1,845,867,435	11,847
2036	5,570,335	9,577	6,460	0.0173	252	1,750,921,710	11,305
2037	5,706,630	9,672	6,538	0.0181	266	1,785,001,792	11,627
2038	5,448,317	8,616	6,119	0.0176	252	1,666,538,080	11,330
2039	5,553,097	8,731	6,199	0.0181	254	1,712,426,151	11,584
2040	5,180,884	7,717	5,792	0.0167	221	1,547,476,901	10,991
2041	5,164,345	7,364	5,705	0.0167	222	1,513,398,513	11,008
2042	5,000,692	6,947	5,545	0.0159	210	1,426,738,301	10,699
2043	4,973,141	6,509	5,436	0.0159	202	1,395,662,722	10,776
Total	**134,188,571**	**154,604**	**122,581**	**0.406**	**8,306**	**43,732,557,038**	**273,981**
Pounds/Gallons per MWh[48]	**902**	**1.04**	**0.82**	**0.000003**	**0.06**	**147**	**2.030**

[47] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[48] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 10: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 1 – NEE)

Year	Annual Social Cost of Carbon
2025	$1,139,132,187
2026	$1,151,025,894
2027	$1,182,993,732
2028	$1,027,875,370
2029	$972,185,689
2030	$815,346,559
2031	$741,565,451
2032	$676,606,840
2033	$726,019,364
2034	$731,664,351
2035	$772,246,675
2036	$771,269,337
2037	$814,965,697
2038	$802,439,822
2039	$851,748,425
2040	$819,299,456
2041	$841,929,891
2042	$848,377,440
2043	$869,547,745

Table 11: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 1 – NEE)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,950,104
2027	$72,370,913
2028	$63,854,206
2029	$59,238,749
2030	$55,323,918
2031	$47,881,107
2032	$43,405,678
2033	$46,538,873
2034	$47,435,734
2035	$51,090,347
2036	$50,898,647
2037	$54,631,126
2038	$55,527,948
2039	$59,194,959
2040	$58,529,071
2041	$60,870,777
2042	$62,289,850
2043	$64,055,746

Table 12: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 1 – NEE)

Year	Target[49]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-1 for detailed GHG emissions calculations for the portfolio.

Portfolio 1 (New ERA Expanded) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 13: Total Financial (Portfolio 1 – NEE)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,836	$12,911	$837	$29,746	$30,584
Difference to preferred plan (Nominal $)	$393	($18)	($1)	$375	$374

Table 14: Total Financial Generation and Transmission (Portfolio 1 – NEE)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$1,508	$971
Transmission (Nominal $)	$1,506	$389

Table 15: Annual Financial (Nominal $) (Portfolio 1 – NEE)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,206
2028	$1,539
2029	$1,401
2030	$1,424
2031	$1,501

[49] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2032	$1,518
2033	$1,552
2034	$1,531
2035	$1,529
2036	$1,597
2037	$1,634
2038	$1,679
2039	$1,717
2040	$1,711
2041	$1,785
2042	$1,835
2043	$1,921

[redacted]

[redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 675 MW of battery storage (including hybrid batteries) built during the RAP in Portfolio 1 – NEE. The amount of curtailment is reduced to zero in 2030 as more batteries are built.

Table 17: Curtailed Intermittent Energy, Annual MWh (Portfolio 1 – NEE)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	185	0	0	185
2026	0	896	0	0	896
2027	0	1,429	0	0	1,429
2028	0	1,811	0	0	1,811
2029	0	52	0	124	176
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**4,373**	**0**	**124**	**4,497**

Table 18: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 1 – NEE)

	Winter	Spring	Summer	Fall
2025	0	118	0	67
2026	13	713	39	131
2027	18	1,189	1	221
2028	61	954	69	727
2029	0	0	12	164
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**92**	**2,974**	**121**	**1,310**

The following table reflects PPA pricing, penalties, and taxes.

Table 19: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 1 – NEE)

	Wind ($)	Solar ($)
2025	$0	$23,999
2026	$0	$145,247
2027	$0	$224,019

2028	$0	$214,350
2029	$0	$18,138
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$625,753**

Portfolio 1 (New ERA Expanded) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 20: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 1 – NEE)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0019-1-ECO	$1.50	$5.85	
2029	200	WI-0013-3-ECO		$14.62	$30.00
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Battery	$1.50	$5.85	
2038	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	$81.56
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
2043	100	Battery	$1.50	$5.85	
2043	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2035	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24
2037	100	Wind + Battery		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2041	100	Solar		$5.85	$56.46
2042	100	Solar		$5.85	

Portfolio 1 (New ERA Expanded) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 1 New ERA Expanded.

Table 21: RAP Planning Reserve Margin, % Annual (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	33%	52%	58%	35%

Table 22: Post-RAP Planning Reserve Margin, % Annual (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	33%	32%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 1 New ERA Expanded.

Table 23: RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 24: Post-RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 1 – NEE.

Table 25: RAP Expected Unserved Energy, Annual MWh (Portfolio 1 – NEE)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 26: Post-RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

2. New ERA Limited Gas (NELG)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 2 (New ERA Limited Gas) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 27: Expansion Plan (Portfolio 2 – NELG)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[55]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
	ST-0002-6-wco	4hr - Battery	West Colorado	100	1	100
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	WI-0013-3-eco	Wind	East Colorado	200	1	200
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	GG-0006-1-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
2033	-	Geothermal Storage	West Colorado	20	1	20
	-	Wind / Battery	New Mexico	100	1	100
2036	-	10hr - Battery	East Colorado	100	1	100
	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2042	-	Wind	East Colorado	100	4	400
	-	Solar	New Mexico	100	2	200
2043	-	Wind	Wyoming / W.Neb	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 2 – NELG.

[55] Each bid is modeled as a single project for purposes of expansion plan selection.

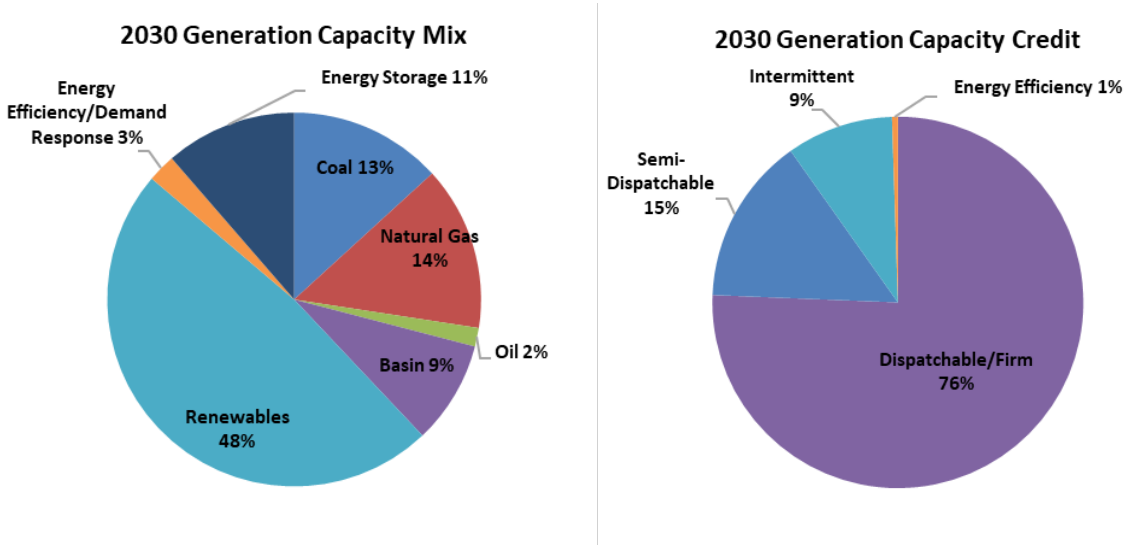
Unit retirements scheduled or selected in the modeling are shown in the following table.[56]

Table 28: Modeled Retirements (Portfolio 2 – NELG)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[57]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 4: Projected Tri-State System Capacity Mix 2030 (Portfolio 2 – NELG)[58, 59]



[56] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[57] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[58] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[59] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 5: Projected Tri-State System Energy Mix 2030 (Portfolio 2 – NELG)[60]

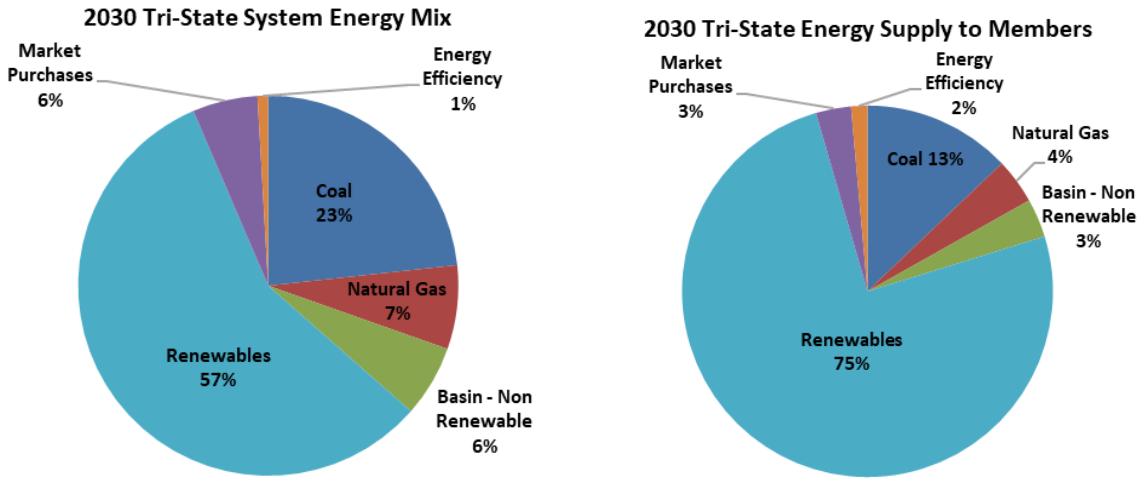


Table 29: Projected Annual Capacity Factors for Thermal Resources (Portfolio 2 – NELG)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	82%
LRS 3	67%	83%	64%	73%	83%	82%	80%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	1%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	25%	18%	24%
GG-0006-1-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 2 (New ERA Limited Gas) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[60] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 30: Environmental Impact - System Wide (Portfolio 2 – NELG) [61]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,684	6,082	7,499	0.0335	974	4,177,652,419	24,195
2027	11,727,659	5,926	7,347	0.0325	958	4,150,755,120	23,895
2028	9,879,304	5,209	6,129	0.0290	839	3,477,044,578	20,198
2029	9,036,223	7,796	6,566	0.0268	726	3,057,173,748	17,831
2030	7,334,742	10,249	6,979	0.0238	606	2,670,517,035	15,863
2031	6,390,985	9,941	6,811	0.0207	369	2,119,971,139	13,074
2032	5,643,142	9,626	6,504	0.0177	258	1,756,894,095	11,314
2033	5,846,331	9,721	6,629	0.0185	276	1,840,356,862	11,660
2034	5,721,745	9,570	6,526	0.0180	272	1,784,592,739	11,401
2035	5,816,518	9,313	6,528	0.0185	267	1,808,182,520	11,756
2036	5,617,103	9,352	6,437	0.0175	253	1,746,259,917	11,294
2037	5,668,595	8,918	6,321	0.0183	262	1,762,046,825	11,511
2038	5,370,590	7,698	5,885	0.0174	240	1,607,675,000	11,165
2039	5,444,002	7,486	5,871	0.0179	237	1,637,977,953	11,421
2040	5,033,242	6,320	5,407	0.0162	202	1,458,912,630	10,787
2041	5,081,355	6,125	5,424	0.0162	205	1,437,999,469	10,924
2042	4,923,968	5,904	5,263	0.0158	200	1,383,150,176	10,618
2043	4,899,783	5,453	5,150	0.0159	192	1,362,250,327	10,712
Total	**133,622,891**	**146,245**	**120,547**	**0.404**	**8,194**	**43,139,330,433**	**272,022**
Pounds/Gallons per MWh[62]	**946**	**1.04**	**0.85**	**0.000003**	**0.06**	**153**	**2.123**

[61] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[62] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 31: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 2 – NELG)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,653,707
2027	$1,174,732,910
2028	$1,026,795,307
2029	$973,309,290
2030	$818,577,657
2031	$739,322,590
2032	$676,519,826
2033	$726,175,264
2034	$736,202,715
2035	$775,083,935
2036	$775,046,549
2037	$809,721,903
2038	$794,053,163
2039	$832,968,427
2040	$796,824,782
2041	$828,400,211
2042	$835,361,013
2043	$856,721,090

Table 32: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 2 – NELG)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,834,755
2027	$72,194,298
2028	$63,843,496
2029	$58,876,581
2030	$54,688,462
2031	$47,192,177
2032	$42,731,594
2033	$46,052,949
2034	$47,065,889
2035	$50,698,390
2036	$50,851,295
2037	$54,083,272
2038	$54,721,101
2039	$58,358,076
2040	$57,442,190
2041	$60,401,484
2042	$61,819,253
2043	$63,671,990

Table 33: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 2 – NELG)

Year	Target[63]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-2 for detailed GHG emissions calculations for the portfolio.

Portfolio 2 (New ERA Limited Gas) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and allowance for funds used during construction (AFUDC), annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 34: Total Financial (Portfolio 2 – NELG)

$, Millions	**Portfolio PVRR** (2024 WACC 5.9%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$16,841	$12,852	$831	$29,693	$30,524
Difference to preferred plan (Nominal $)	$399	($77)	($7)	$322	$314

Table 35: Total Financial Generation and Transmission (Portfolio 2 – NELG)

$, Millions	**Expansion Plan CapEx + AFUDC:**	**Difference to preferred plan**
Generation (Nominal $)	$370	($167)
Transmission (Nominal $)	$1,494	$378

Table 36: Annual Financial (Nominal $) (Portfolio 2 – NELG)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,046
2027	$1,231
2028	$1,312
2029	$1,326

[63] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2030	$1,432
2031	$1,510
2032	$1,571
2033	$1,572
2034	$1,556
2035	$1,552
2036	$1,623
2037	$1,670
2038	$1,709
2039	$1,746
2040	$1,781
2041	$1,821
2042	$1,907
2043	$1,962

[redacted]

64 [redacted]

65 [redacted]

66 [redacted]

67 [redacted]

68 [redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 775 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 38: Curtailed Intermittent Energy, Annual MWh (Portfolio 2 – NELG)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	962	0	0	962
2027	0	853	0	0	853
2028	0	1,132	0	11	1,143
2029	0	242	0	337	579
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,262**	**0**	**348**	**3,610**

Table 39: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 2 – NELG)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	35	669	80	178
2027	33	703	32	85
2028	132	288	26	697
2029	0	0	288	291
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**200**	**1,710**	**426**	**1,274**

The following table reflects PPA pricing, penalties, and taxes.

Table 40: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 2 – NELG)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$156,979
2027	$0	$114,621
2028	$0	$143,388
2029	$0	$56,325
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$480,683**

Portfolio 2 (New ERA Limited Gas) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 41: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 2 – NELG)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0004-10-ECO			
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	200	WI-0013-3-ECO		$14.62	$30.00
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Battery	$1.50	$5.85	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	$81.56
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2027	100	ST-0002-6-WCO	$1.30	$3.25	
2029	307	GG-0006-1-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2033	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46
2042	100	Solar		$5.85	

Portfolio 2 (New ERA Limited Gas) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 2 – NELG.

Table 42: RAP Planning Reserve Margin, % Annual (Portfolio 2 – NELG)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	36%	54%	59%	36%

Table 43: Post-RAP Planning Reserve Margin, % Annual (Portfolio 2 – NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
32%	31%	31%	32%	32%	33%	31%	34%	36%	34%	32%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 2 – NELG.

Table 44: RAP Loss of Load Probability, Hours (Portfolio 2 – NELG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 45: Post-RAP Loss of Load Probability, Hours (Portfolio 2 - NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 2 – NELG.

Table 46: RAP Expected Unserved Energy, Annual MWh (Portfolio 2 - NELG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 47: Post-RAP Loss of Load Probability, Hours (Portfolio 2 - NELG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

3. New ERA Gas Flexibility (FLEX)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 3 (New ERA Gas Flexibility) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 48: Expansion Plan (Portfolio 3 – FLEX)

Year	Bid Project	Technology	Planning Region	Unit Size (MW)	Number of Units[69]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	WI-0016-1-eco	Wind	East Colorado	297	1	297
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
2033	-	Wind / Battery	New Mexico	100	1	100
	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	New Mexico	100	2	200
	-	10hr - Battery	West Colorado	100	1	100
	-	Solar	West Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	West Colorado	100	1	100
2042	-	Wind	East Colorado	100	3	300
	-	Solar	New Mexico	100	1	100
	-	Solar	West Colorado	100	2	200
2043	-	Wind	Wyoming / W.Neb	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 3 – FLEX.

[69] Each bid is modeled as a single project for purposes of expansion plan selection.

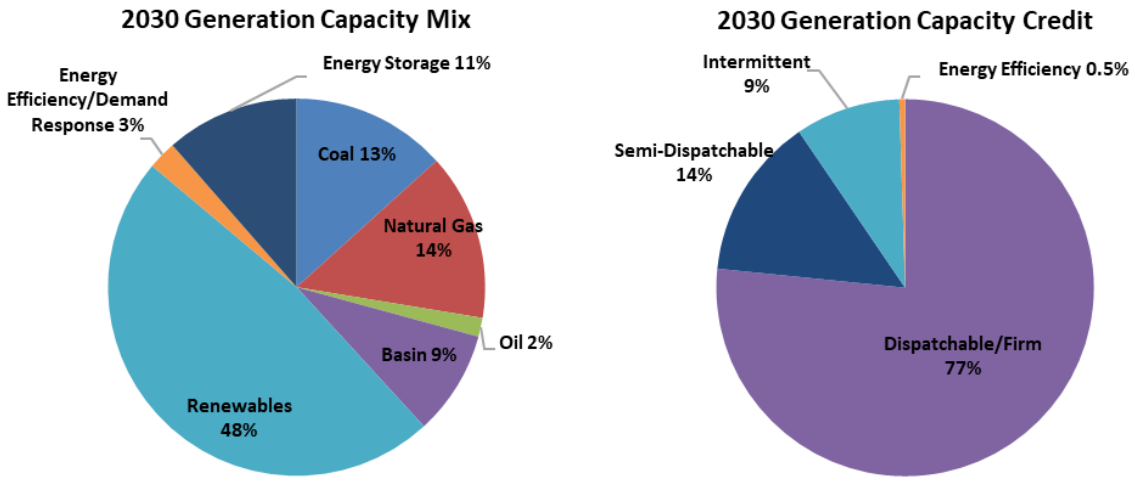
Unit retirements scheduled or selected in the modeling are shown in the following table.[70]

Table 49: Modeled Retirements (Portfolio 3 – FLEX)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[71]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 6: Projected Tri-State System Capacity Mix 2030 (Portfolio 3 – FLEX)[72, 73]



[70] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[71] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[72] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[73] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 7: Projected Tri-State System Energy Mix 2030 (Portfolio 3 – FLEX)[74]

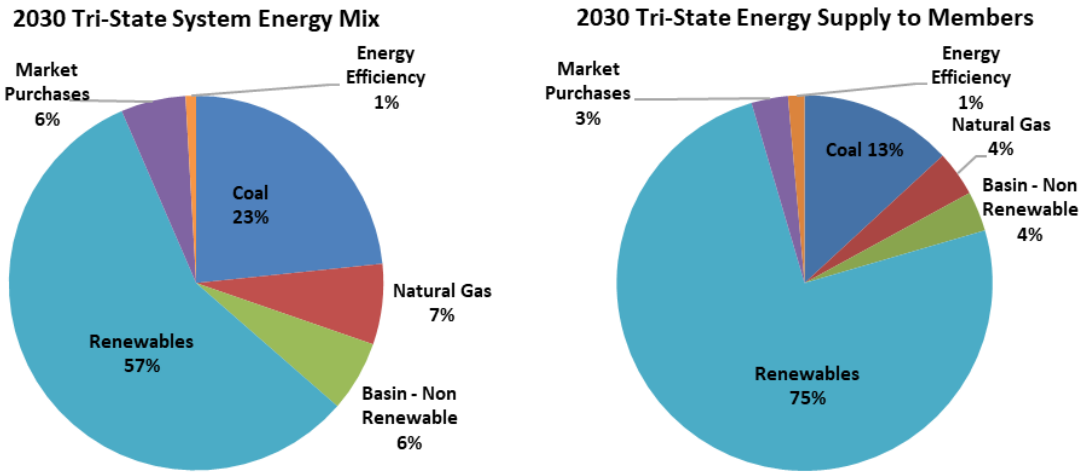


Table 50: Projected Annual Capacity Factors for Thermal Resources (Portfolio 3 – FLEX)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	82%
LRS 3	67%	83%	52%	70%	83%	82%	80%
SPV 3	87%	87%	89%	75%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	22%	16%	21%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 3 (New ERA Gas Flexibility) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[74] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 51: Environmental Impact - System Wide (Portfolio 3 – FLEX) [75]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,943,290	6,082	7,500	0.0335	974	4,177,494,353	24,196
2027	11,568,153	5,770	7,226	0.0311	936	4,045,072,240	23,327
2028	9,779,075	5,148	6,077	0.0284	818	3,407,958,468	19,883
2029	8,967,361	7,781	6,521	0.0267	724	3,038,458,535	17,867
2030	7,315,232	10,260	6,967	0.0237	605	2,657,827,563	16,039
2031	6,350,647	9,935	6,786	0.0206	367	2,096,814,877	13,210
2032	5,635,838	9,629	6,501	0.0176	257	1,753,123,139	11,482
2033	5,820,676	9,711	6,616	0.0184	274	1,827,280,223	11,797
2034	5,720,467	9,667	6,551	0.0179	272	1,784,031,850	11,563
2035	5,832,550	9,741	6,639	0.0185	270	1,814,000,679	11,908
2036	5,602,277	9,601	6,471	0.0175	255	1,753,655,478	11,394
2037	5,653,752	9,638	6,515	0.0177	261	1,752,980,829	11,500
2038	5,458,897	8,694	6,154	0.0176	252	1,654,130,594	11,329
2039	5,548,435	8,783	6,219	0.0180	252	1,690,762,833	11,575
2040	5,178,596	7,783	5,816	0.0165	220	1,530,568,107	10,959
2041	5,191,519	7,349	5,728	0.0167	223	1,503,734,603	11,078
2042	5,095,815	6,784	5,539	0.0165	218	1,460,467,941	10,943
2043	5,039,030	6,269	5,391	0.0164	208	1,427,643,128	10,961
Total	**133,946,532**	**154,182**	**122,485**	**0.404**	**8,246**	**43,275,923,319**	**273,416**
Pounds/Gallons per MWh[76]	**949**	**1.09**	**0.87**	**0.000003**	**0.06**	**153**	**2.134**

[75] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[76] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 52: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 3 – FLEX)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,712,185
2027	$1,158,755,608
2028	$1,016,378,097
2029	$965,892,008
2030	$816,400,243
2031	$734,656,192
2032	$675,644,270
2033	$722,988,638
2034	$736,038,329
2035	$777,220,279
2036	$773,000,815
2037	$807,601,751
2038	$807,109,612
2039	$848,947,387
2040	$819,836,199
2041	$846,359,980
2042	$864,515,211
2043	$881,068,315

Table 53: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 3 – FLEX)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,836,579
2027	$70,477,977
2028	$62,847,444
2029	$58,997,890
2030	$55,296,246
2031	$47,683,283
2032	$43,367,675
2033	$46,595,924
2034	$47,733,888
2035	$51,349,932
2036	$51,298,669
2037	$54,036,042
2038	$55,522,239
2039	$59,145,438
2040	$58,361,648
2041	$61,255,841
2042	$63,710,822
2043	$65,154,538

Table 54: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 3 – FLEX)

Year	Target[77]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-3 for detailed GHG emissions calculations for the portfolio.

Portfolio 3 (New ERA Gas Flexibility) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 55: Total Financial (Portfolio 3 – FLEX)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,761	$12,891	$836	$29,652	$30,488
Difference to preferred plan (Nominal $)	$318	($38)	($2)	$281	$278

Table 56: Total Financial Generation and Transmission (Portfolio 3 – FLEX)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$1,129	$592
Transmission (Nominal $)	$1,457	$340

Table 57: Annual Financial (Nominal $) (Portfolio 3 – FLEX)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,220
2028	$1,371
2029	$1,399
2030	$1,427
2031	$1,503

[77] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2032	$1,525
2033	$1,557
2034	$1,537
2035	$ 1,531
2036	$1,607
2037	$1,639
2038	$1,697
2039	$1,726
2040	$1,751
2041	$1,785
2042	$1,833
2043	$1,906

[redacted]

78 [redacted]

79 [redacted]

80 [redacted]

81 [redacted]

82 [redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 497 MW of wind, 350 MW of solar, and 775 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 59: Curtailed Intermittent Energy, Annual MWh (Portfolio 3 – FLEX)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	101	0	0	101
2026	0	770	0	0	770
2027	0	1,019	0	0	1,019
2028	0	847	0	7	854
2029	0	9	0	207	216
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**2,746**	**0**	**214**	**2,960**

Table 60: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 3 – FLEX)

	Winter	Spring	Summer	Fall
2025	0	60	0	41
2026	13	601	79	77
2027	18	725	52	224
2028	49	412	1	392
2029	0	0	70	146
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**80**	**1,798**	**202**	**880**

The following table reflects PPA pricing, penalties, and taxes.

Table 61: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 3 – FLEX)

	Wind ($)	Solar ($)
2025	$0	$13,166
2026	$0	$125,261
2027	$0	$151,371
2028	$0	$107,958

2029	$0	$18,876
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$416,632**

Portfolio 3 (New ERA Gas Flexibility) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 62: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 3 – FLEX)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	50	ST-0018-1-ECO	$1.50	$5.85	
2029	297	WI-0016-1-ECO		$14.62	$30.00
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2038	100	Wind + Battery		$5.85	$81.56
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2033	20	Geothermal Storage	$1.30	$3.25	
2036	100	Solar		$5.85	
2036	100	Battery	$1.50	$5.85	
2041	100	Solar		$3.25	
2042	100	Solar		$6.56	
2042	100	Solar		$6.56	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2033	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46

Portfolio 3 (New ERA Gas Flexibility) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 3 – FLEX.

Table 63: RAP Planning Reserve Margin, % Annual (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	33%	54%	58%	36%

Table 64: Post-RAP Planning Reserve Margin, % Annual (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	32%	32%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 3 – FLEX.

Table 65: RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 66: Post-RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 3 – FLEX.

Table 67: RAP Expected Unserved Energy, Annual MWh (Portfolio 3 – FLEX)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 68: Post-RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

4. FLEX Shafer Replacement (FLEXSR)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 4 (FLEX Shafer Replacement) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 69: Expansion Plan (Portfolio 4 – FLEXSR)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[83]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	ST-0004-6-eco	4hr - Battery	East Colorado	150	1	150
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	PV-0006-8-eco	Solar	East Colorado	200	1	200
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	GG-0006-2-wco	Combustion Turbine	West Colorado	38.36	8	307
2030	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming/ W. Neb.	200	1	200
2033	-	Wind / Battery	East Colorado	100	2	200
2036	-	Wind / Battery	New Mexico	100	2	200
	-	Wind / Battery	East Colorado	100	1	100
	-	Geothermal Storage	West Colorado	20	1	20
	-	Solar	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	1	100
	-	Wind / Battery	New Mexico	100	1	100
2042	-	Solar	New Mexico	100	2	200
	-	Wind	Wyoming/ W. Neb.	100	1	100
	-	Wind	East Colorado	100	2	200
2043	-	Wind / Battery	East Colorado	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 4 – FLEXSR.

[83] Each bid is modeled as a single project for purposes of expansion plan selection.

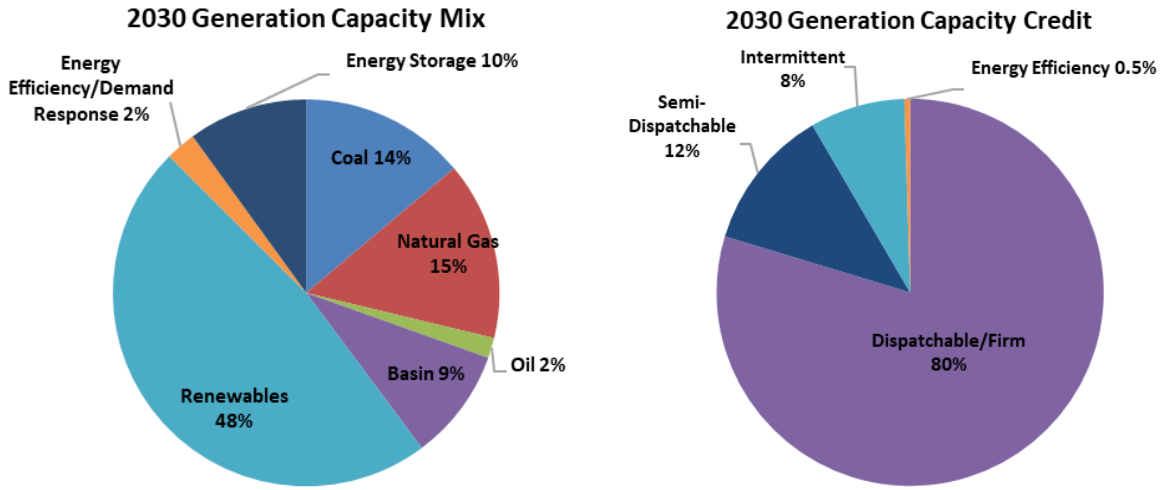
Unit retirements scheduled or selected in the modeling are shown in the following table.[84]

Table 70: Modeled Retirements (Portfolio 4 – FLEXSR)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[85]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 8: Projected Tri-State System Capacity Mix 2030 (Portfolio 4 – FLEXSR)[86, 87]



[84] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[85] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[86] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[87] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 9: Projected Tri-State System Energy Mix 2030 (Portfolio 4 – FLEXSR)[88]

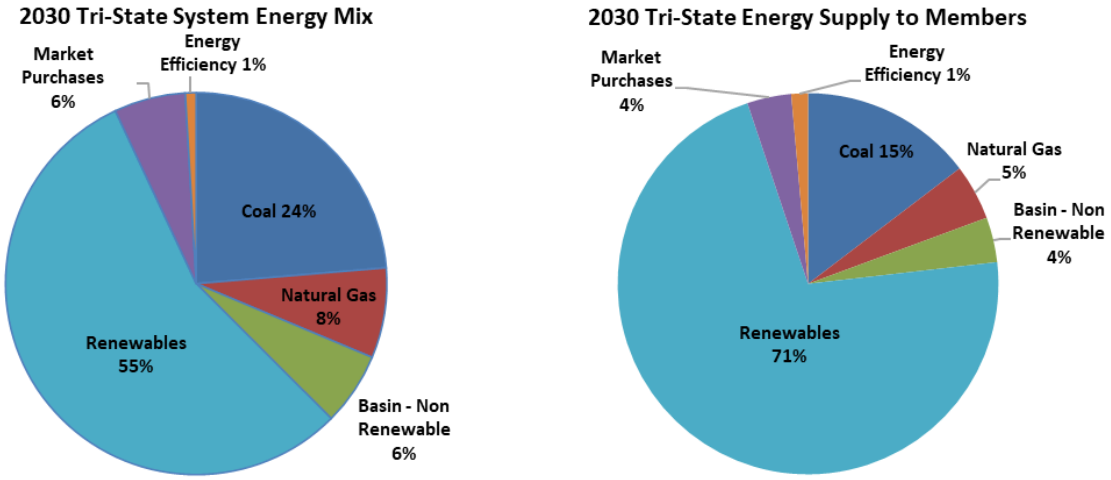


Table 71: Projected Annual Capacity Factors for Thermal Resources (Portfolio 4 – FLEXSR)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	53%	70%	82%	82%	80%
SPV 3	87%	87%	89%	75%	65%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	25%	22%	23%
GG-0006-2-wco	0%	0%	0%	0%	40%	40%	40%

Portfolio 4 (FLEX Shafer Replacement) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[88] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 72: Environmental Impact - System Wide (Portfolio 4 – FLEXSR) [89]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,421	6,082	7,499	0.0335	974	4,177,610,423	24,195
2027	11,568,735	5,770	7,227	0.0311	937	4,046,667,348	23,331
2028	9,819,361	5,161	6,103	0.0283	814	3,399,083,138	19,893
2029	9,204,229	7,855	6,616	0.0273	767	3,162,829,891	18,345
2030	7,412,404	10,284	7,047	0.0238	610	2,702,448,101	16,151
2031	6,458,059	9,980	6,884	0.0207	371	2,133,619,472	13,382
2032	5,712,026	9,667	6,578	0.0177	259	1,771,382,260	11,617
2033	5,853,864	9,745	6,652	0.0185	275	1,823,859,347	11,905
2034	5,797,935	9,690	6,616	0.0180	276	1,814,833,359	11,665
2035	5,898,663	9,785	6,694	0.0187	274	1,828,879,124	12,058
2036	5,625,841	9,611	6,460	0.0178	260	1,775,162,952	11,446
2037	5,698,331	9,682	6,499	0.0184	270	1,777,568,735	11,664
2038	5,351,664	8,533	6,016	0.0175	249	1,631,722,206	11,143
2039	5,433,584	8,599	6,069	0.0180	250	1,664,645,441	11,377
2040	5,111,931	7,566	5,683	0.0167	220	1,515,089,860	10,911
2041	5,218,379	7,217	5,684	0.0171	227	1,526,405,089	11,155
2042	5,033,011	6,829	5,500	0.0163	216	1,447,560,576	10,793
2043	4,988,533	6,377	5,382	0.0162	206	1,414,798,721	10,834
Total	**134,373,893**	**153,989**	**122,479**	**0.406**	**8,315**	**43,514,083,924**	**274,271**
Pounds/Gallons per MWh[90]	**952**	**1.09**	**0.87**	**0.000003**	**0.06**	**154**	**2.141**

[89] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[90] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 73: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 4 – FLEXSR)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,628,339
2027	$1,158,813,840
2028	$1,020,565,222
2029	$991,405,565
2030	$827,244,896
2031	$747,081,881
2032	$684,777,928
2033	$727,110,962
2034	$746,005,989
2035	$786,030,277
2036	$776,252,143
2037	$813,969,586
2038	$791,254,956
2039	$831,374,435
2040	$809,282,328
2041	$850,738,875
2042	$853,860,285
2043	$872,238,852

Table 74: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 4 – FLEXSR)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,833,899
2027	$70,489,792
2028	$62,881,612
2029	$60,575,560
2030	$55,682,337
2031	$48,304,507
2032	$43,879,284
2033	$47,023,762
2034	$48,155,833
2035	$51,996,947
2036	$51,534,377
2037	$54,805,537
2038	$54,614,207
2039	$58,132,606
2040	$58,102,968
2041	$61,679,010
2042	$62,837,645
2043	$64,400,027

Table 75: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 4 – FLEXSR)

Year	Target[91]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-4 for detailed GHG emissions calculations for the portfolio.

Portfolio 4 (FLEX Shafer Replacement) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 76: Total Financial (Portfolio 4 – FLEXSR)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,443	$12,928	$838	$29,371	$30,210

Table 77: Total Financial Generation and Transmission (Portfolio 4 – FLEXSR)

$, Millions	Expansion Plan CapEx + AFUDC:
Generation (Nominal $)	$537
Transmission (Nominal $)	$1,116

Table 78: Annual Financial (Nominal $) (Portfolio 4 – FLEXSR)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,050
2027	$1,227
2028	$1,306
2029	$1,362
2030	$1,383
2031	$1,435
2032	$1,489
2033	$1,509
2034	$1,511
2035	$1,509

[91] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2036	$1,599
2037	$1,606
2038	$1,669
2039	$1,695
2040	$1,702
2041	$1,745
2042	$1,779
2043	$1,855

[redacted]

92 [redacted]

93 [redacted]

94 [redacted]

95

96 [redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 300 MW of solar, and 650 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 80: Curtailed Intermittent Energy, Annual MWh (Portfolio 4 – FLEXSR)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	945	0	0	945
2027	0	1,432	0	0	1,432
2028	0	707	0	10	717
2029	0	453	0	20	473
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,610**	**0**	**30**	**3,640**

Table 81: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 4 – FLEXSR)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	13	672	77	183
2027	19	1,127	58	228
2028	44	527	0	146
2029	0	0	1	472
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**76**	**2,376**	**136**	**1,052**

The following table reflects PPA pricing, penalties, and taxes.

Table 82: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 4 – FLEXSR)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$152,487
2027	$0	$193,537
2028	$0	$90,037
2029	$0	$51,807
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$497,237**

Portfolio 4 (FLEX Shafer Replacement) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

As described in the Executive Summary Portfolio Analysis section above and in Attachment G, Tri-State analyzed Portfolio 4 – FLEXSR bid selections for transmission interconnection and upgrade cost considerations and the potential to utilize surplus interconnection, and implemented transmission modeling optimizations. As a result of this analysis, the FLEXSR preferred portfolio avoids significant transmission upgrade costs during the RAP.

Table 83: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 4 – FLEXSR)

Year	**Size** *(MW)*	**Type**	**Interconnection Cost** *($M)*	**Network Upgrade at POI Cost** *($M)*	**Network Upgrade for Size** *($M)*
Eastern Colorado (ECO) Transmission Area					
2027	150	ST-0004-6-ECO	$0.00		
2028	200	PV-0006-8-ECO		$5.85	
2028	100	ST-0004-10-ECO			
2029	200	WI-0013-3-ECO		$14.62	$30.00
2033	100	Wind + Battery		$5.85	$81.56
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	$148.74
2042	100	Wind		$5.85	
2042	100	Wind		$5.85	
2043	100	Wind + Battery		$5.85	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2029	307	GG-0006-2-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2036	20	Geothermal Storage	$1.30	$3.25	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	
2042	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2036	100	Solar		$5.85	$56.46
2036	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2042	100	Solar		$3.25	
2042	100	Solar		$3.25	

Portfolio 4 (FLEX Shafer Replacement) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 4 – FLEXSR.

Table 84: RAP Planning Reserve Margin, % Annual (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	38%	52%	54%	34%

Table 85: Post-RAP Planning Reserve Margin, % Annual (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
32%	32%	32%	33%	32%	32%	32%	35%	37%	35%	32%	32%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 4 – FLEXSR.

Table 86: RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 87: Post-RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 4 – FLEXSR.

Table 88: RAP Expected Unserved Energy, Annual MWh (Portfolio 4 – FLEXSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 89: Post-RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

5. No New Gas (NNG)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 5 (No New Gas) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 90: Expansion Plan (Portfolio 5 – NNG)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[97]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	PV-0004-5-wco	Solar	West Colorado	140	1	140
2028	ST-0019-1-eco	Iron Air Battery	East Colorado	100	1	100
	ST-0004-9-eco	4hr - Battery	East Colorado	100	1	100
	ST-0004-8-wco	4hr - Battery	West Colorado	200	1	200
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	WI-0013-3-eco	Wind	East Colorado	200	1	200
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
2030	PC-0009-2P-eco	Solar / Battery	East Colorado	150	1	150
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
	WI-0013-2-wyo-wne	Wind	Wyoming / W.Neb	200	1	200
2033	-	Wind / Battery	New Mexico	100	2	200
2035	-	Geothermal Storage	West Colorado	20	1	20
2036	-	Wind / Battery	East Colorado	100	2	200
	-	Wind / Battery	New Mexico	100	1	100
2037	-	Wind / Battery	East Colorado	100	1	100
	-	Geothermal[98]	West Colorado	12	1	12
2038	-	Wind / Battery	East Colorado	100	2	200
2042	-	Wind / Battery	East Colorado	100	1	100
	-	Solar	New Mexico	100	1	100
	-	Solar	West Colorado	100	2	200
2043	-	Wind / Battery	East Colorado	100	2	200
	-	Wind / Battery	Wyoming / W.Neb	100	1	100

[97] Each bid is modeled as a single project for purposes of expansion plan selection.
[98] Enhanced Geothermal Baseload (*see* Attachment B-8). Unit size is 25 MW, dispatchable maximum of 12 MW.

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 5 – NNG.

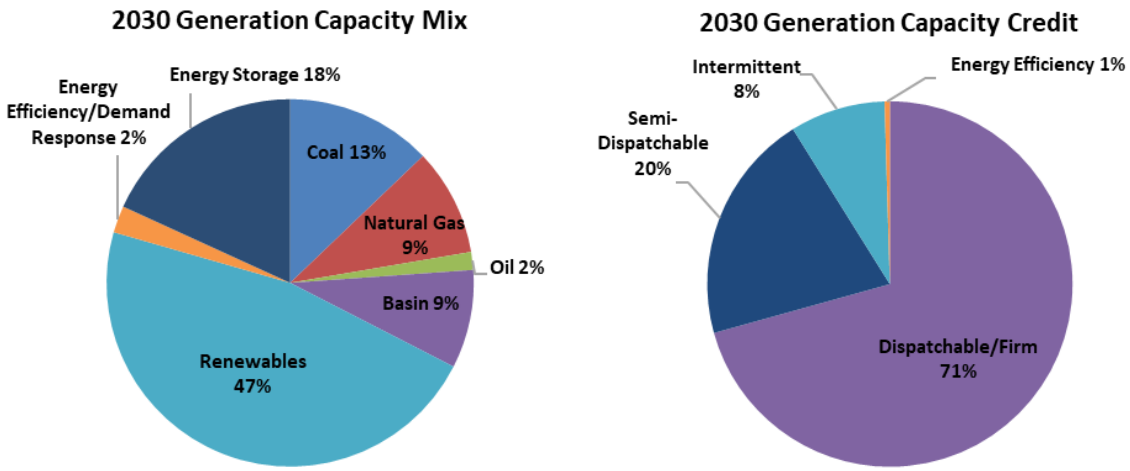
Unit retirements scheduled or selected in the modeling are shown in the following table.[99]

Table 91: Modeled Retirements (Portfolio 5 – NNG)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[100]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 10: Projected Tri-State System Capacity Mix 2030 (Portfolio 5 – NNG) [101]



[99] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[100] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[101] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

Figure 11: Projected Tri-State System Energy Mix 2030 (Portfolio 5 – NNG) [102]

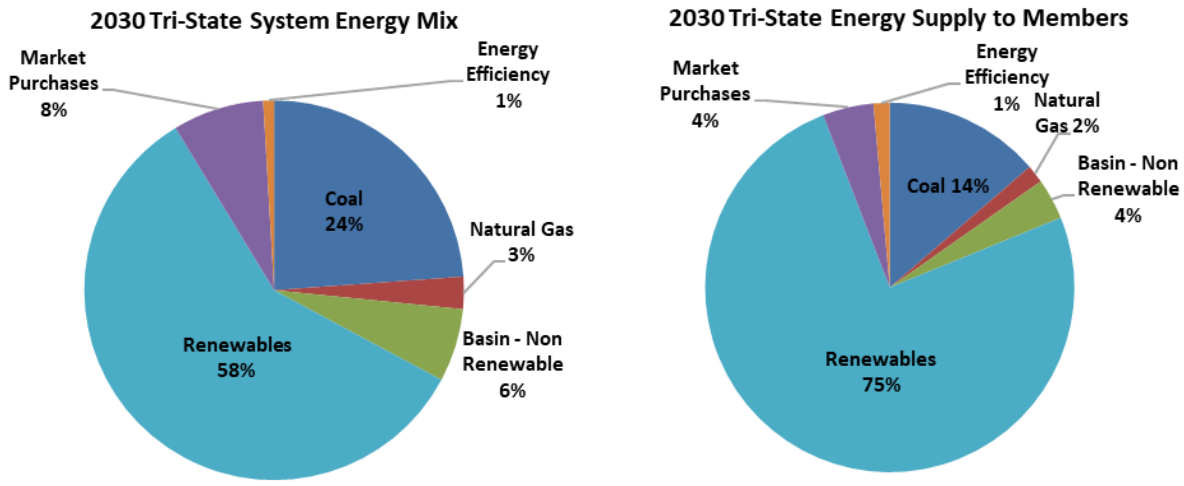


Table 92: Projected Annual Capacity Factors for Thermal Resources (Portfolio 5 – NNG)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	64%	73%	82%	81%	79%
SPV 3	87%	87%	89%	77%	60%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	1%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	30%	27%	27%

Portfolio 5 (No New Gas) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[102] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 93: Environmental Impact - System Wide (Portfolio 5 – NNG)[103]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,942,265	6,082	7,499	0.0335	974	4,177,589,447	24,195
2027	11,726,163	5,927	7,347	0.0326	958	4,152,095,618	23,899
2028	9,883,456	5,211	6,132	0.0290	839	3,476,173,634	20,198
2029	8,959,962	4,974	5,831	0.0267	701	2,986,775,243	17,946
2030	7,013,425	4,657	5,500	0.0237	557	2,526,716,133	16,088
2031	5,999,591	4,341	5,298	0.0205	314	1,924,297,995	13,251
2032	5,264,320	4,036	5,000	0.0176	203	1,558,763,516	11,552
2033	5,390,667	4,091	5,043	0.0184	219	1,627,608,477	11,744
2034	5,289,574	4,044	4,975	0.0179	218	1,586,884,489	11,497
2035	5,408,588	4,109	5,066	0.0184	216	1,627,443,211	11,822
2036	5,196,722	3,983	4,903	0.0177	203	1,565,648,310	11,396
2037	5,297,401	4,068	4,958	0.0183	216	1,599,262,492	11,628
2038	5,013,729	3,964	4,754	0.0175	205	1,473,591,656	11,134
2039	5,111,419	4,012	4,817	0.0179	206	1,513,672,212	11,383
2040	4,871,635	3,892	4,696	0.0167	185	1,405,407,473	10,925
2041	4,990,642	3,996	4,805	0.0171	195	1,416,107,699	11,183
2042	4,890,992	3,945	4,778	0.0163	188	1,362,105,080	10,925
2043	4,853,274	3,938	4,726	0.0165	186	1,351,564,503	10,934
Total	**129,348,747**	**84,826**	**103,400**	**0.407**	**7,640**	**41,231,625,068**	**274,106**
Pounds/Gallons per MWh[104]	**916**	**0.60**	**0.73**	**0.000003**	**0.05**	**146**	**2.139**

[103] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.

[104] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 94: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 5 – NNG)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,613,302
2027	$1,174,583,082
2028	$1,027,226,838
2029	$965,095,102
2030	$782,717,739
2031	$694,045,278
2032	$631,105,309
2033	$669,577,102
2034	$680,596,397
2035	$720,724,943
2036	$717,042,375
2037	$756,699,323
2038	$741,290,549
2039	$782,081,140
2040	$771,240,407
2041	$813,611,550
2042	$829,766,536
2043	$848,588,980

Table 95: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 5 – NNG)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,833,909
2027	$72,206,255
2028	$63,846,020
2029	$59,255,701
2030	$55,464,509
2031	$47,830,289
2032	$43,632,908
2033	$46,386,308
2034	$47,461,289
2035	$50,983,048
2036	$51,311,539
2037	$54,636,281
2038	$54,569,169
2039	$58,162,802
2040	$58,177,007
2041	$61,837,927
2042	$63,603,366
2043	$64,997,048

Table 96: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 5 – NNG)

Year	Target[105]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-5 for detailed GHG emissions calculations for the portfolio.

Portfolio 5 (No New Gas) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 97: Total Financial (Portfolio 5 – NNG)

$, Millions	**Portfolio PVRR** (2024 WACC 5.9%)	**SCoC NPV (2.5%)**	**SCoM NPV (2.5%)**	**Portfolio PVRR inclusive of SCoC NPV**	**Portfolio PVRR inclusive of SCoC NPV & SCoM NPV**
	$17,067	$12,429	$838	$29,496	$30,334
Difference to preferred plan (Nominal $)	$624	($499)	($1)	$125	$124

Table 98: Total Financial Generation and Transmission (Portfolio 5 – NNG)

$, Millions	**Expansion Plan CapEx + AFUDC:**	**Difference to preferred plan**
Generation (Nominal $)	$652	$115
Transmission (Nominal $)	$3,008	$1,891

Table 99: Annual Financial (Nominal $) (Portfolio 5 – NNG)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,049
2027	$1,212
2028	$1,415
2029	$1,423
2030	$1,441

[105] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2031	$1,523
2032	$1,544
2033	$1,580
2034	$1,555
2035	$1,610
2036	$1,706
2037	$1,739
2038	$1,722
2039	$1,766
2040	$1,789
2041	$1,818
2042	$1,868
2043	$1,954



106 [redacted]

107 [redacted]

108 [redacted]

109 [redacted]

110 [redacted]

[redacted]

Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 1,275 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 101: Curtailed Intermittent Energy, Annual MWh (Portfolio 5 – NNG)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	73	0	0	73
2026	0	860	0	0	860
2027	0	759	0	0	759
2028	0	1,707	0	0	1,707
2029	0	62	0	255	317
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**3,461**	**0**	**255**	**3,716**

Table 102: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 5 – NNG)

	Winter	Spring	Summer	Fall
2025	0	50	0	23
2026	47	579	57	177
2027	33	672	16	38
2028	117	709	0	881
2029	0	0	176	141
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**197**	**2,010**	**249**	**1,260**

The following table reflects PPA pricing, penalties, and taxes.

Table 103: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 5 – NNG)

	Wind ($)	Solar ($)
2025	$0	$9,370
2026	$0	$138,416
2027	$0	$105,188
2028	$0	$198,901

2029	$0	$31,189
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$483,064**

Portfolio 5 (No New Gas) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

Table 104: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 5 – NNG)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2028	100	ST-0004-9-ECO	$1.50	$5.85	$30.00
2028	100	ST-0004-10-ECO			
2028	100	ST-0019-1-ECO	$1.50	$5.85	
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	50	ST-0018-1-ECO	$1.50	$5.85	
2029	200	WI-0013-3-ECO		$14.62	$81.56
2030	150	PC-0009-2P-ECO		$14.62	$130.00
2036	100	Wind + Battery		$14.62	
2036	100	Wind + Battery		$5.85	
2037	100	Wind + Battery		$6.56	$1,098.06
2038	100	Wind + Battery		$6.56	
2038	100	Wind + Battery		$6.56	
2042	100	Wind + Battery		$6.56	
2043	100	Wind + Battery		$6.56	
2043	100	Wind + Battery		$6.56	
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2027	140	PV-0004-5-WCO		$3.25	$47.06
2028	200	ST-0004-8-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2035	20	Geothermal Storage	$1.30	$3.25	
2037	12	Geothermal	$1.30	$3.25	
2042	100	Solar		$5.85	
2042	100	Solar		$5.85	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	$119.24

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
2043	100	Wind + Battery		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2029	100	PV-0004-4-NM		$10.94	$165.62
2033	100	Wind + Battery		$5.85	$363.20
2033	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	$56.46

Portfolio 5 (No New Gas) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 5 – NNG.

Table 105: RAP Planning Reserve Margin, % Annual (Portfolio 5 – NNG)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	39%	53%	58%	35%

Table 106: Post-RAP Planning Reserve Margin, % Annual (Portfolio 5 – NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	33%	31%	31%	31%	33%	36%	33%	32%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 5 – NNG.

Table 107: RAP Loss of Load Probability, Hours (Portfolio 5 - NNG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 108: Post-RAP Loss of Load Probability, Hours (Portfolio 5 - NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 5 – NNG.

Table 109: RAP Expected Unserved Energy, Annual MWh (Portfolio 5 – NNG)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 110: Post-RAP Loss of Load Probability, Hours (Portfolio 5 – NNG)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

6. No New Gas Shafer Replacement (NNGSR)

Assumptions unique to the portfolio are identified in Attachment B-3.

Portfolio 6 (No New Gas Shafer Replacement) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

Table 111: Expansion Plan (Portfolio 6 – NNGSR)

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[111]	Total MW
2026	ST-0002-5-wco	4hr - Battery	West Colorado	50	1	50
2027	ST-0004-6-eco	4hr - Battery	East Colorado	150	1	150
2028	ST-0009-4-nm	4hr - Battery	New Mexico	100	1	100
	ST-0004-8-wco	4hr - Battery	West Colorado	200	1	200
	ST-0004-10-eco	4hr - Battery	East Colorado	100	1	100
	ST-0004-9-eco	4hr - Battery	East Colorado	100	1	100
	PV-0006-8-eco	Solar	East Colorado	200	1	200
	PC-0018-1P-nm	Solar / Battery	New Mexico	100	1	100
2029	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	WI-0013-3-eco	Wind	East Colorado	200	1	200
2030	WI-0013-2-wyo-wne	Wind	Wyoming/ W. Neb.	200	1	200
	ST-0009-3-wco	4hr - Battery	West Colorado	200	1	200
2033	-	Wind / Battery	East Colorado	100	2	200
2036	-	Geothermal Storage	West Colorado	20	1	20
	-	Wind / Battery	New Mexico	100	3	300
2037	-	Wind / Battery	East Colorado	100	1	100
2038	-	Wind / Battery	East Colorado	100	2	200
2041	-	Solar	West Colorado	100	1	100
2042	-	Solar	West Colorado	100	1	100
	-	Wind	East Colorado	100	2	200
	-	Solar	New Mexico	100	2	200
2043	-	Solar	West Colorado	100	1	100
	-	Wind	Wyoming/ W. Neb.	100	1	100

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 6 – NNGSR.

[111] Each bid is modeled as a single project for purposes of expansion plan selection.

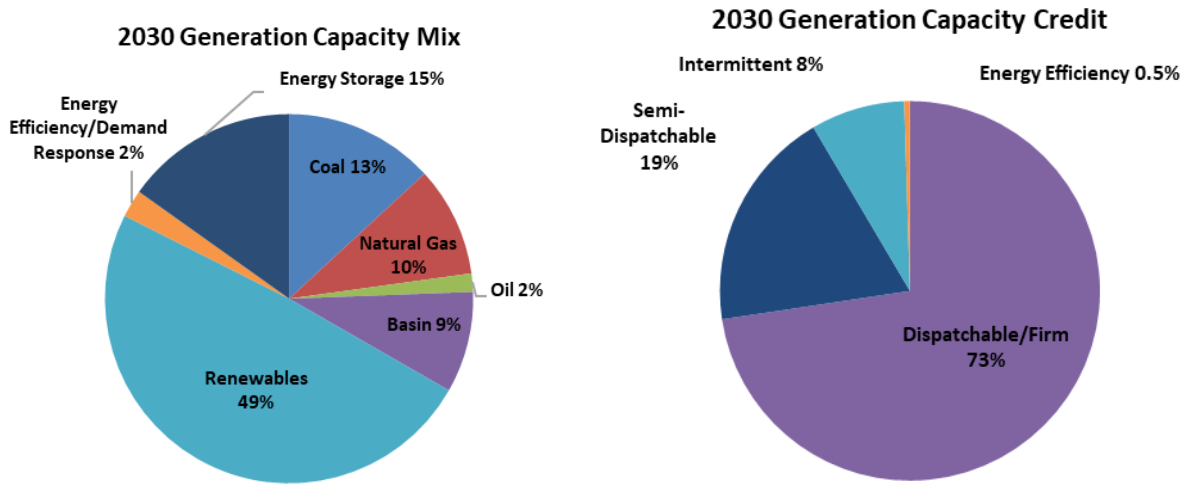
Unit retirements scheduled or selected in the modeling are shown in the following table.[112]

Table 112: Modeled Retirements (Portfolio 6 – NNGSR)

Location	MW	Technology	Date
Craig 1	427	Coal	12/31/2025
Craig 3	448	Coal	1/1/2028
Craig 2	410	Coal	9/30/2028
Springerville 3	418	Coal	3/1/2031[113]

Resulting system capacity and energy mix, based on the modeling are shown below.

Figure 12: Projected Tri-State System Capacity Mix 2030 (Portfolio 6 – NNGSR) [114, 115]



[112] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[113] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[114] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[115] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

Figure 13: Projected Tri-State System Energy Mix 2030 (Portfolio 6 – NNGSR)[116]

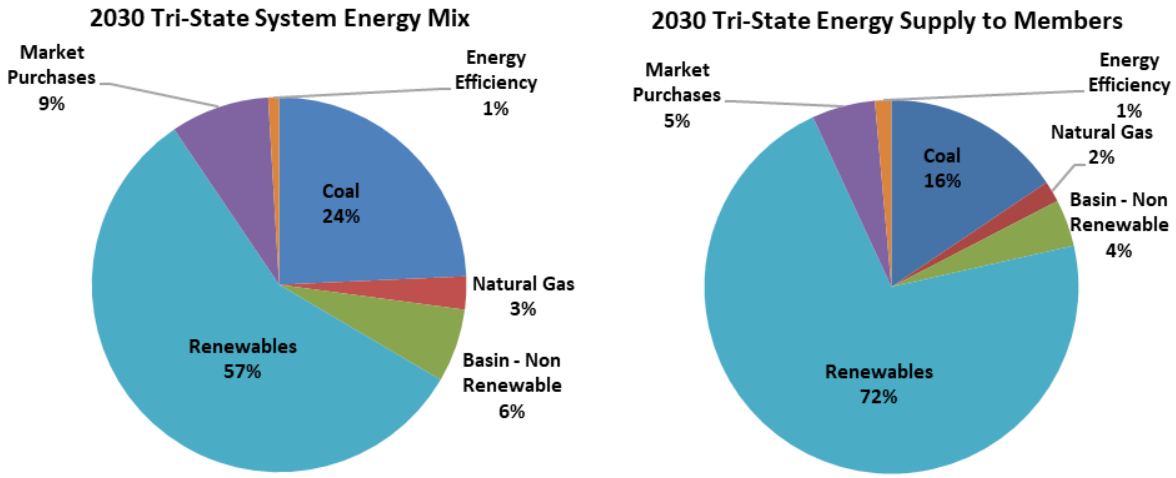


Table 113: Projected Annual Capacity Factors for Thermal Resources (Portfolio 6 – NNGSR)

Thermal Resource	2025	2026	2027	2028	2029	2030	2031
Craig 1	33%	-	-	-	-	-	-
Craig 2	36%	37%	38%	24%	-	-	-
Craig 3	19%	19%	19%	-	-	-	-
LRS 2	77%	78%	89%	88%	82%	75%	83%
LRS 3	67%	83%	53%	70%	81%	81%	78%
SPV 3	87%	87%	89%	75%	65%	42%	12%
Burlington	0%	0%	0%	0%	0%	0%	0%
Knutson	6%	5%	3%	0%	0%	0%	0%
Limon	4%	3%	0%	0%	0%	0%	0%
Pyramid	7%	1%	3%	0%	0%	0%	0%
Shafer	35%	35%	35%	35%	29%	27%	23%

Portfolio 6 (No New Gas Shafer Replacement) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[116] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

Table 114: Environmental Impact - System Wide (Portfolio 6 – NNGSR)[117]

Year	CO_2 (ST)	SO_2 (ST)	NO_x (ST)	Hg (ST)	PM (ST)	Water (gallons)	CH4 (MT CO2e)
2025	12,244,922	5,556	7,270	0.0304	859	3,899,917,881	22,405
2026	11,946,206	6,083	7,503	0.0335	974	4,178,260,972	24,199
2027	11,570,025	5,771	7,228	0.0311	936	4,046,421,059	23,332
2028	9,814,861	5,160	6,100	0.0283	815	3,401,715,998	19,898
2029	9,111,475	5,027	5,871	0.0272	737	3,073,163,383	18,316
2030	7,050,577	4,679	5,541	0.0238	558	2,532,813,977	16,162
2031	6,019,427	4,364	5,342	0.0204	312	1,913,037,441	13,312
2032	5,363,900	4,052	5,095	0.0176	206	1,604,501,764	11,641
2033	5,520,168	4,151	5,180	0.0184	223	1,661,803,495	11,946
2034	5,414,719	4,107	5,110	0.0180	221	1,615,591,795	11,712
2035	5,560,472	4,185	5,220	0.0186	221	1,665,887,399	12,084
2036	5,239,029	3,999	4,961	0.0176	203	1,573,524,559	11,453
2037	5,344,620	4,099	5,025	0.0182	215	1,590,771,662	11,726
2038	5,084,182	4,014	4,837	0.0175	205	1,470,546,688	11,293
2039	5,164,519	4,055	4,885	0.0180	205	1,504,603,982	11,518
2040	4,894,020	3,929	4,744	0.0167	183	1,379,333,329	11,025
2041	5,034,909	4,021	4,859	0.0171	196	1,413,662,279	11,266
2042	4,876,519	3,942	4,765	0.0163	188	1,347,184,439	10,913
2043	4,887,594	3,957	4,771	0.0165	186	1,347,404,577	10,997
Total	**130,142,142**	**85,151**	**104,306**	**0.405**	**7,642**	**41,220,146,679**	**275,198**
Pounds/Gallons per MWh[118]	**922**	**0.60**	**0.74**	**0.000003**	**0.05**	**146**	**2.148**

[117] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO_2, SO_2 and NO_x are per net MWh; HG and particulate matter (PM) are per gross MWh.
[118] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

Table 115: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 6 – NNGSR)

Year	Annual Social Cost of Carbon
2025	$1,138,459,687
2026	$1,152,993,624
2027	$1,158,943,111
2028	$1,020,097,553
2029	$981,414,787
2030	$786,863,978
2031	$696,339,955
2032	$643,043,287
2033	$685,662,450
2034	$696,698,482
2035	$740,964,313
2036	$722,879,934
2037	$763,444,178
2038	$751,707,224
2039	$790,205,684
2040	$774,784,316
2041	$820,828,229
2042	$827,311,151
2043	$854,589,790

Table 116: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 6 – NNGSR)

Year	Annual Social Cost of Methane
2025	$61,742,239
2026	$69,847,236
2027	$70,492,985
2028	$62,895,824
2029	$60,478,517
2030	$55,718,807
2031	$48,051,268
2032	$43,969,826
2033	$47,182,943
2034	$48,348,612
2035	$52,112,380
2036	$51,565,121
2037	$55,096,401
2038	$55,345,788
2039	$58,855,626
2040	$58,711,741
2041	$62,293,992
2042	$63,533,142
2043	$65,368,924

Table 117: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 6 – NNGSR)

Year	Target[119]	Forecast
2025	26%	29%
2026	36%	39%
2027	46%	47%
2030	80%	80%

See Attachment D-6 for detailed GHG emissions calculations for the portfolio.

Portfolio 6 (No New Gas Shafer Replacement) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

Table 118: Total Financial (Portfolio 6 – NNGSR)

$, Millions	Portfolio PVRR (2024 WACC 5.9%)	SCoC NPV (2.5%)	SCoM NPV (2.5%)	Portfolio PVRR inclusive of SCoC NPV	Portfolio PVRR inclusive of SCoC NPV & SCoM NPV
	$16,531	$12,509	$842	$29,039	$29,881
Difference to preferred plan (Nominal $)	$88	($420)	$3	($332)	($329)

Table 119: Total Financial Generation and Transmission (Portfolio 6 – NNGSR)

$, Millions	Expansion Plan CapEx + AFUDC:	Difference to preferred plan
Generation (Nominal $)	$265	($272)
Transmission (Nominal $)	$1,100	($16)

Table 120: Annual Financial (Nominal $) (Portfolio 6 – NNGSR)

Year	Total Annual Revenue Requirement ($, Millions)
2025	$1,059
2026	$1,051
2027	$1,236
2028	$1,317
2029	$1,335
2030	$1,358

[119] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

Year	Total Annual Revenue Requirement ($, Millions)
2031	$1,447
2032	$1,480
2033	$1,507
2034	$ 1,526
2035	$1,523
2036	$1,610
2037	$1,618
2038	$1,685
2039	$1,711
2040	$1,741
2041	$1,786
2042	$1,839
2043	$1,899



120 [redacted]

121 [redacted]

122 [redacted]

123 [redacted]

124 [redacted]



Curtailments

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 300 MW of solar, and 1,200 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

Table 122: Curtailed Intermittent Energy, Annual MWh (Portfolio 6 – NNGSR)

	Existing Wind	Existing Solar	Bid Wind	Bid Solar	Total
2025	0	101	0	0	101
2026	0	1,205	0	0	1,205
2027	0	1,233	0	0	1,233
2028	0	285	0	13	298
2029	0	5	0	0	5
2030	0	0	0	0	0
2031	0	0	0	0	0
RAP Total	**0**	**2,829**	**0**	**13**	**2,842**

Table 123: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 6 – NNGSR)

	Winter	Spring	Summer	Fall
2025	0	60	0	41
2026	72	825	98	210
2027	36	938	54	205
2028	182	57	0	59
2029	0	0	0	5
2030	0	0	0	0
2031	0	0	0	0
RAP Total	**290**	**1,880**	**152**	**520**

The following table reflects PPA pricing, penalties, and taxes.

Table 124: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 6 – NNGSR)

	Wind ($)	Solar ($)
2025	$0	$13,166
2026	$0	$166,014
2027	$0	$171,286
2028	$0	$42,920
2029	$0	$798
2030	$0	$0
2031	$0	$0
RAP Total	**$0**	**$394,184**

Portfolio 6 (No New Gas Shafer Replacement) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

As described in the Executive Summary Portfolio Analysis section above and in Attachment G, Tri-State analyzed Portfolio 6 – NNGSR bid selections for transmission interconnection and upgrade cost considerations and the potential to utilize surplus interconnection, and implemented transmission modeling optimizations, to ensure that the benefits of this approach were evaluated under both a new gas and no new gas portfolio. As a result of this analysis, this portfolio avoids significant transmission upgrade costs during the RAP similar to the preferred portfolio, but has a higher PVRR.

Table 125: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 6 – NNGSR)

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Eastern Colorado (ECO) Transmission Area					
2026	150	ST-0004-6-ECO			
2028	200	PV-0006-8-ECO		$5.85	
2028	100	ST-0004-10-ECO			
2028	100	ST-0004-9-ECO			$30.00
2029	150	ST-0010-4-ECO	$1.50	$5.85	
2029	100	ST-0017-1-ECO	$1.50	$14.62	
2029	200	WI-0013-3-ECO		$14.62	
2033	100	Wind		$5.85	$81.56
2033	100	Wind		$5.85	
2037	100	Wind + Battery		$5.85	
2038	100	Wind + Battery		$5.85	$148.74
2038	100	Wind + Battery		$5.85	
2042	100	Wind		$14.62	
2042	100	Wind		$5.85	

Year	Size *(MW)*	Type	Interconnection Cost *($M)*	Network Upgrade at POI Cost *($M)*	Network Upgrade for Size *($M)*
Western Colorado (WCO) Transmission Area					
2026	50	ST-0002-5-WCO	$1.30	$10.94	
2028	200	ST-0004-8-WCO	$1.70	$6.56	
2030	200	ST-0009-3-WCO	$1.50	$5.85	
2036	20	Geothermal Storage	$1.30	$3.25	
2041	100	Solar		$5.85	
2042	100	Solar		$6.56	
2043	100	Solar		$6.56	
Wyoming (WYO) Transmission Area					
2030	200	WI-0013-2-WYO-WNE		$14.62	
2043	100	Wind		$6.56	
New Mexico (NM) Transmission Area)					
2028	100	PC-0018-1P-NM		$10.94	
2028	100	ST-0009-4-NM	$1.30	$3.25	
2036	100	Wind + Battery		$5.85	$363.20
2036	100	Wind + Battery		$5.85	
2036	100	Wind + Battery		$5.85	
2042	100	Solar		$5.85	
2042	100	Solar		$5.85	

Portfolio 6 (No New Gas Shafer Replacement) – Reliability Analysis

PRM, LOLH, and EUE results are ("Level 1 Reliability Metrics") as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

Planning Reserve Margin

The following table provides the annual PRM resulting from Portfolio 6 – NNGSR.

Table 126: RAP Planning Reserve Margin, % Annual (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
24%	24%	26%	42%	51%	53%	33%

Table 127: Post-RAP Planning Reserve Margin, % Annual (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
31%	31%	31%	32%	31%	31%	31%	33%	36%	34%	31%	31%

Loss of Load Hours

The following table provides the annual LoLH resulting from Portfolio 6 – NNGSR.

Table 128: RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 129: Post-RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

Expected Unserved Energy

The following table provides the annual EUE resulting from Portfolio 6 – NNGSR.

Table 130: RAP Expected Unserved Energy, Annual MWh (Portfolio 6 – NNGSR)

2025	2026	2027	2028	2029	2030	2031
0	0	0	0	0	0	0

Table 131: Post-RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
0	0	0	0	0	0	0	0	0	0	0	0

7. Renewable Back-up Bid Pool (BkRE)

The approach to modeling back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. The expansion plan selected the following renewable bids as the most economic for the back-up pool.

Table 132: Renewable Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[125]	Total MW
2027	PC-0004-1P-nm	Solar / Battery	New Mexico	90	1	90
	PV-0004-5-wco	Solar	West Colorado	140	1	140
2029	WI-0016-1-eco	Wind	East Colorado	297	1	297
	PC-0021-1P-wco	Solar / Battery	West Colorado	125	1	125
	PV-0004-4-nm	Solar	New Mexico	100	1	100
	WI-0005-3-eco	Wind	East Colorado	150	1	150

[125] Each bid is modeled as a single project for purposes of expansion plan selection.

8. Standalone Storage Back-up Bid Pool (BkST)

The approach to modeling back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. The expansion plan selected the following standalone storage bids as the most economic for the back-up pool.

Table 133: Standalone Storage Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[126]	Total MW
2027	ST-0002-6-wco	4hr - Battery	West Colorado	100	1	100
2028	ST-0006-3-nm	4hr - Battery	New Mexico	100	1	100
2029	ST-0018-1-eco	4hr - Battery	East Colorado	50	1	50
	ST-0010-4-eco	4hr - Battery	East Colorado	150	1	150
	ST-0017-1-eco	4hr - Battery	East Colorado	100	1	100

[126] Each bid is modeled as a single project for purposes of expansion plan selection.

9. Gas Plant Back-up Bids (BkNG)

The approach to back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. Only one alternative gas plant bid is available during the RAP, therefore Tri-State did not conduct further modeling to determine a gas plant back-up bid pool.

Table 134: Gas Plant Back-up Bid Pool

Year	Project	Technology	Planning Region	Unit Size (MW)	Number of Units[127]	Total MW
2030	GG-0005-1-wco	Combustion Turbine	West Colorado	45.325	4	181.3

[127] Each bid is modeled as a single project for purposes of expansion plan selection.

Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase II portfolios is provided below.

Environmental Analysis

The following tables identify each portfolio's system-wide forecasted CO_2 and CH_4 emissions in 2026 and 2031.

Figure 14: Comparison of Forecasted System CO_2 Emissions in 2026 and 2031, by Portfolio

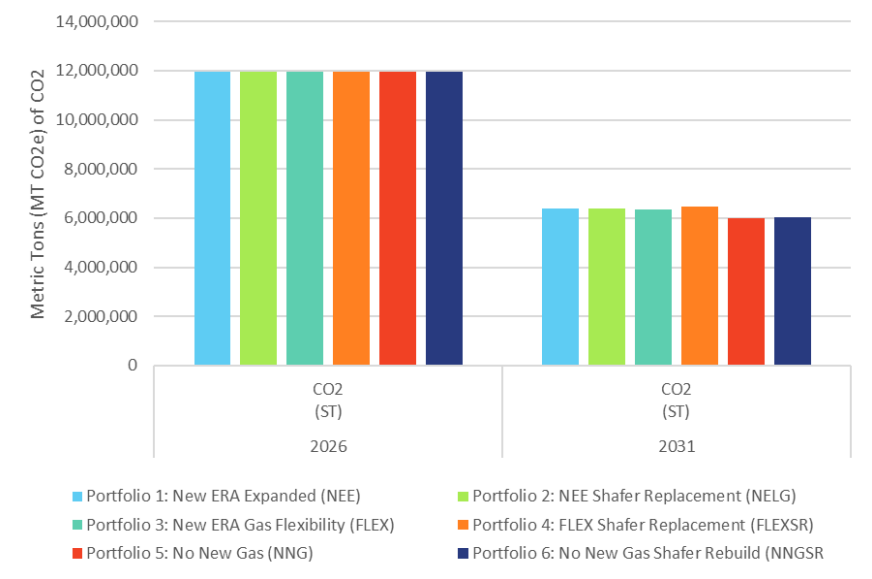
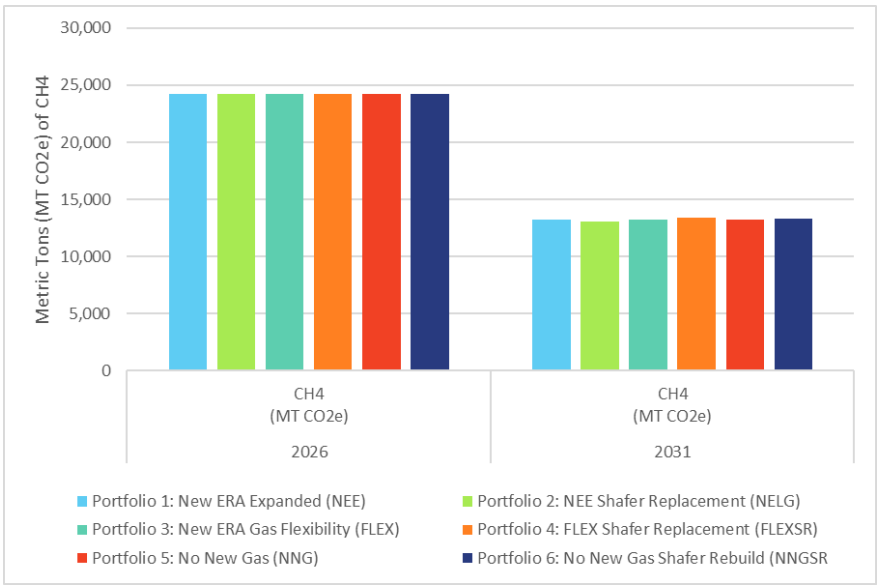


Figure 15: Comparison of Forecasted System CH_4 Emissions in 2026 and 2031, by Portfolio



The following table identifies each portfolio's forecasted achievements toward Colorado GHG reduction targets. Modeling indicates all Phase II portfolios are able to achieve the Colorado GHG reduction

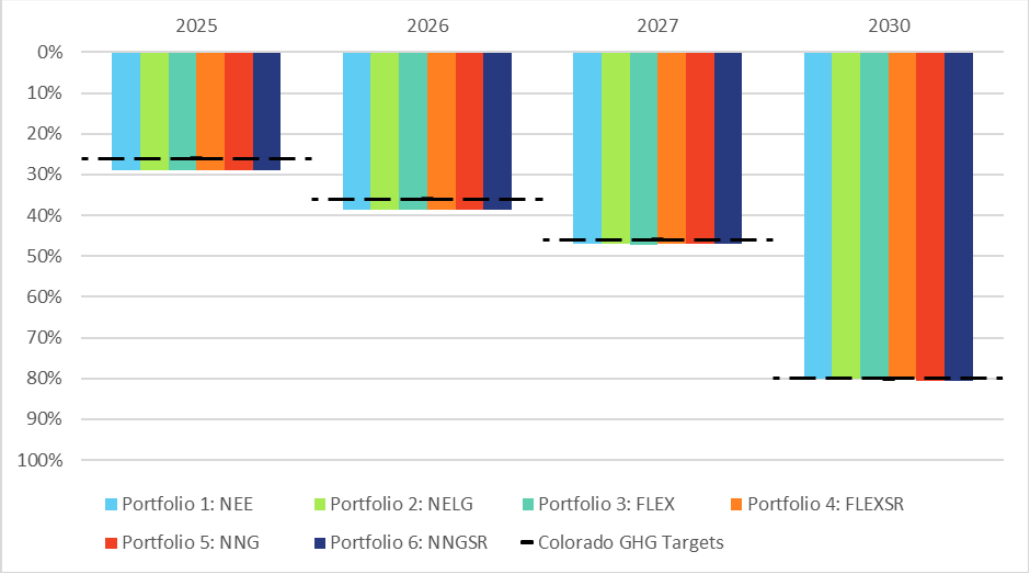
targets in 2025,[128] 2026, 2027, and 2030. Forecasted emissions reductions in 2030 in Phase II meet the minimum statutory requirement, and do not vary substantially across portfolios. This is driven in part by the model seeking a least-cost expansion plan, based on actual bid pricing (versus generic resources in Phase I), as well as new APCD guidance issued in December 2024 on the approach to forecasting market emission rates. In Phase II, emission rates for market purchases and sales are reflective of expectations that the residual mix of supply from the market is anticipated to be primarily thermal energy.

Additional discussion of Tri-State's consideration of the environmental results of the portfolio analyses can be found in the Portfolio Analysis section of the Executive Summary; and discussion of SCoC and SCoM in the Financial Analysis section below.

Table 135: Comparison of Forecasted Colorado GHG Reduction by Portfolio in GHG Target Years

	2025	2026	2027	2030
Portfolio 1: New ERA Expanded	29%	39%	47%	80%
Portfolio 2: New ERA Limited Gas	29%	39%	47%	80%
Portfolio 3: New ERA Gas Flexibility (FLEX)	29%	39%	47%	80%
Portfolio 4: FLEX Shafer Replacement	29%	39%	47%	80%
Portfolio 5: No New Gas (NNG)	29%	39%	47%	80%
Portfolio 6: NNG Shafer Replacement	29%	39%	47%	80%

Figure 16: Comparison of Portfolio Achievements Toward Colorado GHG Reduction Targets



[128] Trending at the end of Q1-2025 is positive toward achievement of Tri-State's first GHG reduction target.

Figure 17: Comparison of Colorado CO2e

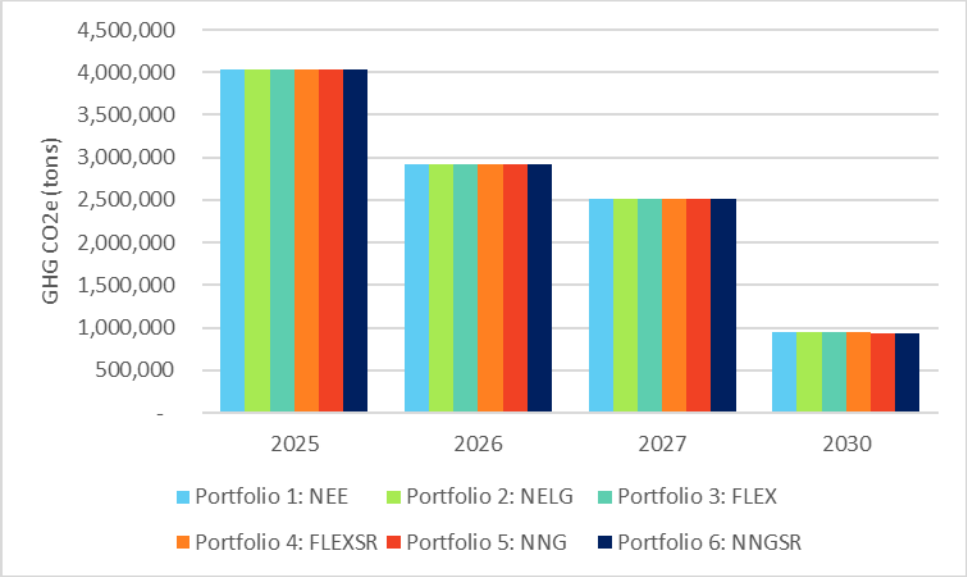


Figure 18: Comparison of SCoC During the RAP

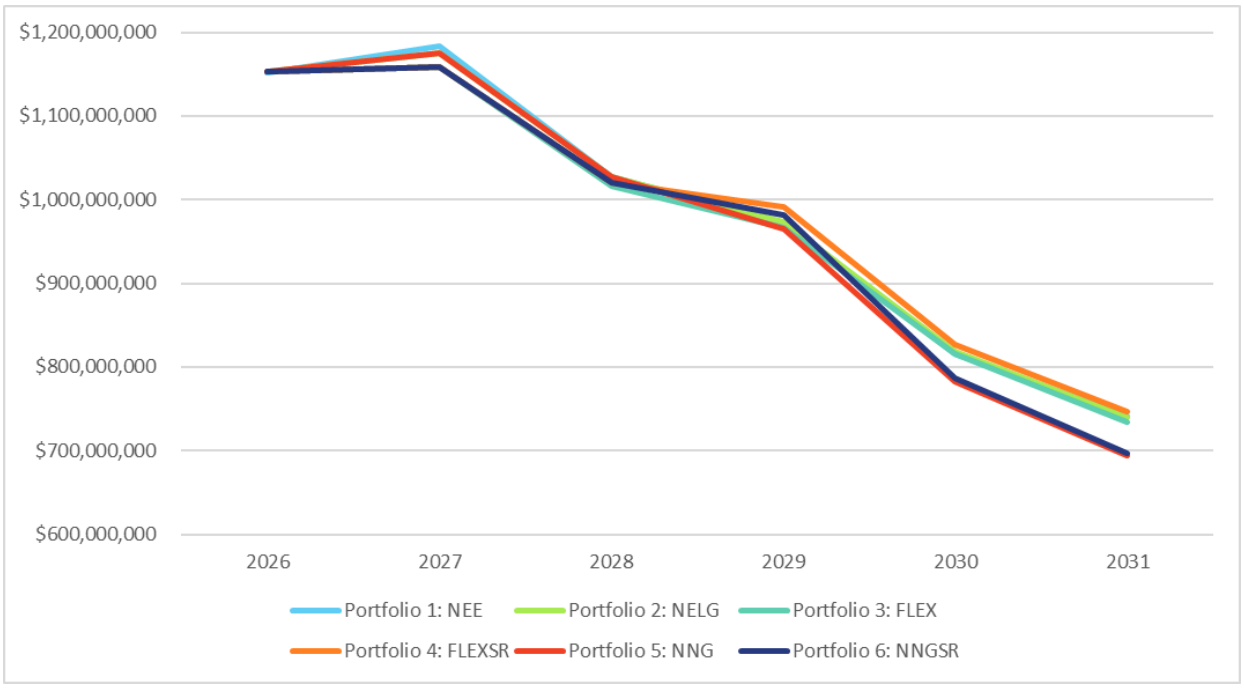
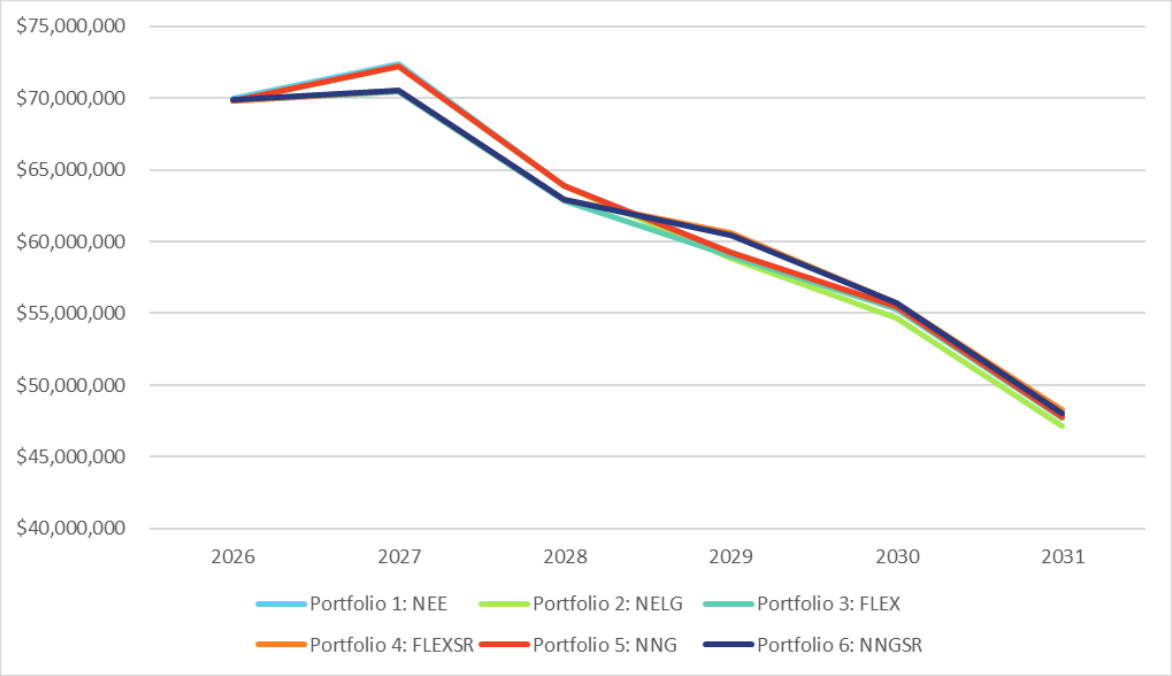


Figure 19: Comparison of SCoM During the RAP



Financial Analysis

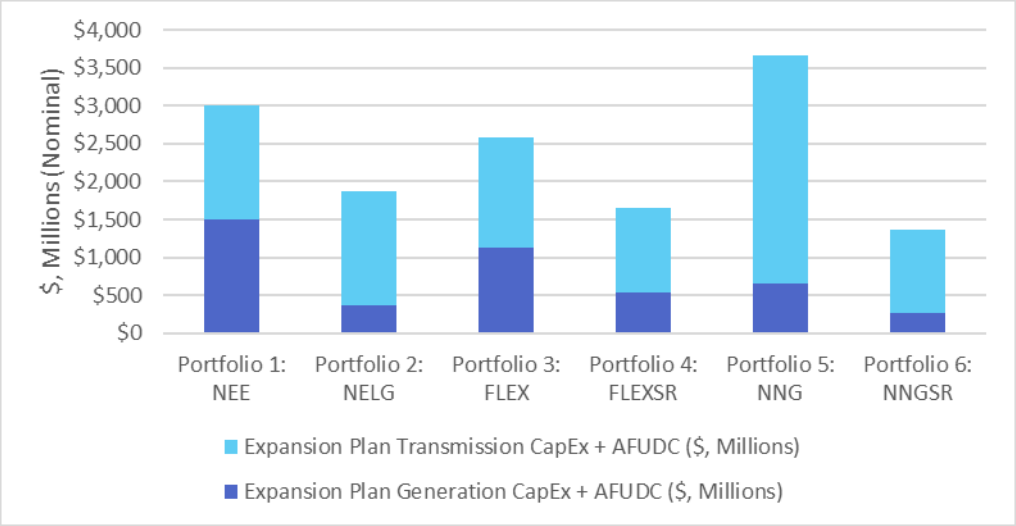
The following table compares total financial results for each portfolio, both with and without the SCoC and SCoM. Portfolio 4 – FLEXSR is the lowest cost plan on a PVRR basis, requiring fewer new resource acquisitions than other portfolios while achieving comparable emissions reductions and reliability results—an important value for Tri-State's Members. Further discussion of the financial benefits achieved with Portfolio 4 – FLEXSR bid selections is identified in Attachment G.

Table 136: Comparison of PVRR

	PVRR ($, Millions)	**PVRR w/SCoC and SCoM ($, Millions)**
Portfolio 1: New ERA Expanded	$16,836	$30,584
Portfolio 2: New ERA Limited Gas	$16,841	$30,524
Portfolio 3: New ERA Gas Flexibility	$16,761	$30,488
Portfolio 4: FLEX Shafer Replacement	$16,443	$30,210
Portfolio 5: No New Gas	$17,067	$30,334
Portfolio 6: No New Gas Shafer Replacement	$16,531	$29,881

The following figure compares capital expenditures and MW additions by portfolio.

Figure 20: Comparison of Generation and Transmission CapEx (Nominal $) During the RPP



As shown in below, the MW level and type of resource additions selected in Portfolios 2 and 3 are relatively similar. Renewable MWs were relatively consistent across all portfolios, except for Portfolio 3 which selected more wind and less solar. Portfolios 1-4 selected a gas plant bid and had a similar amount of storage MW selections, whereas Portfolios 5 and 6, which did not allow new gas, required a considerably larger amount of storage resource additions. Portfolio 4, the preferred portfolio, requires the least amount of resource additions with less transmission capital expenditures. Portfolio 5 requires more MW resource additions than other portfolios in order to maintain system reliability without the addition of a dispatchable gas resource, but at a higher PVRR than any other portfolio. Tri-State is concerned about the potential risk in overreliance on 4-hour batteries suggested by the resource additions in Portfolios 5 and 6; Tri-State has not yet deployed any batteries on its system and storage technologies, including longer duration storage options, are anticipated to make advancements in the coming years.

Table 137: Comparison of MW Additions by Portfolio, by Technology over the RAP

MW	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
Wind	400	400	497	400	400	400
Solar	240	240	100	200	240	200
Standalone Storage -Short Duration	450	650	650	600	1,050	1,150
Standalone Storage - Long Duration	100	0	0	0	100	0
Gas	307	307	307	307	0	0
Solar Hybrid	250	250	250	100	250	100
RAP Total	**1,747**	**1,847**	**1,804**	**1,607**	**2,040**	**1,850**
Solar Hybrid – Battery Storage Component	125	125	125	50	125	50
RAP Total w/Hybrid Storage	**1,872**	**1,972**	**1,929**	**1,657**	**2,165**	**1,900**

Table 138: Comparison of Number of Bids by Portfolio, by Technology over the RAP

	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
Wind	2	2	2	2	2	2
Solar	2	2	1	1	2	1
Standalone Storage -Short Duration	4	6	6	5	9	9
Standalone Storage - Long Duration	1	0	0	0	1	0
Gas	1	1	1	1	0	0
Solar Hybrid	2	2	2	1	2	1
RAP Total	**12**	**13**	**12**	**10**	**16**	**13**

Table 139 below identifies the percentage of Tri-State's system energy and energy supplied to Members that is forecasted to be renewable, for each portfolio in 2030. Table 140 identifies the percentage of generation capacity mix that is renewable for each portfolio in 2030. Table 141 identifies the percentage of generation capacity credit that is dispatchable/firm for each portfolio in 2030. While the preferred portfolio yields a slightly lower percentage of renewables on an energy supply basis, on a generation capacity supply basis the preferred portfolio has a similar percentage of renewables in its mix as the other portfolios. Importantly, all portfolios achieve Tri-State's aspirational target of having 70 percent clean supply to Members in 2030, but the preferred portfolio does so at the least cost.

Table 139: Comparison of Renewables' Contribution to System and Member Supply in 2030, by Portfolio

	2030 System Energy Mix	2030 Tri-State Energy Supply to Members
	% Renewables	
Portfolio 1: NEE	57%	75%
Portfolio 2: NELG	57%	75%
Portfolio 3: FLEX	57%	75%
Portfolio 4: FLEXSR	55%	71%
Portfolio 5: NNG	58%	75%
Portfolio 6: NNGSR	57%	72%

Table 140: Comparison of Renewables' Contribution to Generation Capacity in 2030, by Portfolio

	2030 Generation Capacity Mix
	% Renewables
Portfolio 1: NEE	49%
Portfolio 2: NELG	48%
Portfolio 3: FLEX	48%
Portfolio 4: FLEXSR	48%
Portfolio 5: NNG	47%
Portfolio 6: NNGSR	49%

Table 141: Comparison of Dispatchable/Firm Contribution to the System Mix in 2030, by Portfolio

	2030 Generation Capacity Credit
	% Dispatchable/Firm
Portfolio 1: NEE	78%
Portfolio 2: NELG	76%
Portfolio 3: FLEX	77%
Portfolio 4: FLEXSR	80%
Portfolio 5: NNG	71%
Portfolio 6: NNGSR	73%

Curtailments

The following table identifies the annual total curtailment costs (PPA pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type. None of the portfolios result in wind PPA curtailment costs. Significant solar curtailment costs in all portfolios reflects the inherent challenges in integrating a large amount of intermittent resources into the system in a short timespan. More intermittent resources leads to more curtailment, but storage additions mitigate curtailments.

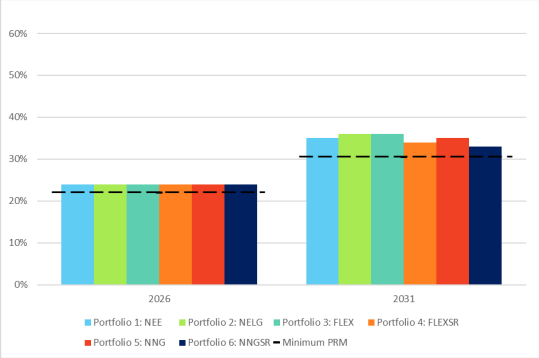
Table 142: Comparison of Solar Curtailment Costs by Portfolio, Real (2024) $

	Portfolio 1: NEE	Portfolio 2: NELG	Portfolio 3: FLEX	Portfolio 4: FLEXSR	Portfolio 5: NNG	Portfolio 6: NNGSR
2026	$145,247	$156,979	$125,261	$152,487	$138,416	$166,014
2027	$224,019	$114,621	$151,371	$193,537	$105,188	$171,286
2028	$214,350	$143,388	$107,958	$90,037	$198,901	$42,920
2029	$18,138	$56,325	$18,876	$51,807	$31,189	$798
2030	$0	$0	$0	$0	$0	$0
2031	$0	$0	$0	$0	$0	$0
RAP Total	**$601,754**	**$471,313**	**$403,466**	**$487,868**	**$473,694**	**$381,018**

Reliability Analysis

PRMs are relatively consistent across all portfolios. Increasing PRMs after 2026 occur as a result of the large amount of intermittent resource additions during the RAP.

Figure 21: Comparison of PRMs During the RAP



Each of the portfolios met Level 1 and 2 Reliability Metrics. The preferred portfolio (FLEXSR) achieves reliability in the most cost-effective manner.

NNG and NNGSR portfolios rely on an extensive amount of storage resources to maintain reliability, creating a heavy reliance on a semi-dispatchable technology during the energy transition—a technology that Tri-State has not yet deployed. Storage technology may evolve and improve in both cost and performance in the coming years, thus Tri-State and its Members seek to make investment during this RAP in a manner that result in a balanced and diversified technology mix, at the least cost.

Conclusion

This Implementation Report provides extensive detail on the multiple portfolios modeled. Tri-State believes this analysis builds a clear record that supports approval of Tri-State's preferred portfolio, FLEXSR, including as a result of the analyses provided in Attachments G and H. Tri-State requests the Commission approve Tri-State's preferred portfolio, Portfolio 4 – FLEXSR, as the final cost-effective resource plan for Phase II of the 2023 ERP, pursuant to Rule 3605(h)(II).

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-88:
Tri-State 2023 ERP Modeling Assumptions

Colorado PUC E-Filings System

Modeling Assumptions

The following table and discussion identify the modeling assumptions to be used in Phase I of Tri-State's 2023 ERP.

Table 1: Modeling Assumptions

Category	Assumption	Description of Modeling Input
Financial	Electric and Gas Forward Curves, and Transport Cost	• Horizon[1] 2023 Spring Forecasts for electric and gas forward curves • Transport adders based on interstate gas provider rates
	Coal Forward Curve	March 2023 forecast in real and nominal dollars
	Capital Expenditures and Fixed O&M	Tri-State 2023 O&M Budget and 10-Year Capital Plan
	Variable O&M	2023 O&M Budget of thermal resource VOMs
	Annual Inflation Forecast	Annual inflation projections as of February 2023
	Depreciation Costs and Schedules	2023 Depreciation Study will inform the rate that existing assets are depreciated in the financial modeling
	Renewable and Storage Generic Resource Prices – PPAs and Build Transfers	Updated based on 2020 ERP Phase II bid responses, IRA impacts, latest PTC/ITC, and $1/MWh Wyoming Wind Tax
	Gas Generic Resource Build Prices	B&V reviewed and refreshed generic gas pricing
	Innovative Technology Pricing	Newly added resource types and modeling assumptions (e.g., Small Modular Reactors, Hydrogen, Molten Salt Long-Term Storage, Iron Air Storage, Geothermal, etc.)
	Resource Integration Adder (Ancillary Service Costs)	Generic resources (as applicable) as follows: WCO, WY-WNE, and ECO updated with WACM; and NM updated with PNM
	Discount Rate / Weighted Average Cost of Capital (WACC)	Updated to 4.12%
	LRS 2 & 3 Retirement Cost Profile	Reflects continuation of fixed and capex costs through useful life
	Springerville Unit 3 (SPV 3) Retirement Cost Profile	Financing and equity partner penalties applicable if unit retired early
	Craig Station Decommissioning Cost	Reflects third-party cost estimate, and Tri-State's share of the cost
	Book Life for Generic Li-Ion Batteries, Renewables, and Gas	Use of book life assumptions for each generic resource and useful life for each existing resource
	Third Party Transmission	• Reflects network and firm point to point transmission available between planning regions

[1] Horizons Energy is a data and analytics consulting company providing market price forecasts for the energy industry. See: https://www.horizons-energy.com/market-price-forecasting/.

		• Added ability to procure additional transmission between planning regions as available at a cost.
Operational	CRSP Hydro Forecast	Forecasted capacity from CRSP hydro contract reflects continued reduction through the planning period due to drought.
	Load Forecast	Forecast as of Summer 2022 with United Power and Northwest Rural Public Power District exiting May 1, 2024 and Mountain Parks exiting February 1, 2025
		Partial Requirements Contracts for May 2021 and May 2022 Open Seasons (excluding Mountain Parks) included as applicable load reductions beginning January 2026
	Beneficial Electrification	Achievable-Moderate level from 2023 BE Potential Study[2]
	Distributed Generation Forecast	Forecast of Member DG as of March 2023 with appropriate Member exits (United Power and Mountain Parks)
	Constraints	Updated constraints on new resource builds and transmission interconnection
	Level I & II Reliability Metrics	Scenarios were modeled to meet minimum Level I and II reliability requirements
	Thermal Build Constraint	No thermal builds allowed before 2028
	Gas Retirement Constraint	No gas resources allowed to retire
	Coal Unit Uptime	Uptime minimum 12 hours
	Coal Unit Downtime	Downtime minimum 8 hours
	Craig 3 Modeling	Craig 3 is modeled in ECON mode
	Craig Unit Retirements	• Craig Units 1 and 2 retirements are modeled to occur on the announced dates. • Craig Unit 3 is modeled to retire between 2028-2029.[3]
	Tri-State Exit MBPP[4]	Allowed in modeling beginning January 1, 2027
	SPV 3 Retirement	Allowed in modeling beginning January 1, 2037
	SPV 3 Max Capacity	SPV 3 rerated to 419 MW per 2022 testing
	Effective Load Carrying Capability (ELCC)	Based on third-party study
	Scheduled Outages	Planned outage schedules updated for all thermal units
	Forced Outage Factors	Applied unit-specific rates based on 5 years of historical data from GADs. Updated forced outage method in dispatch runs to have random outage days instead of a derate.
	Modeling of Market Sales and Purchases Depths	• Market sales and purchases hourly depth updated. • Values are reflective of:

[2] Attachment G-3 of the ERP Report (LKT-1)
[3] Also see Attachment B-3 of the ERP Report (LKT-1) for unique scenario assumptions.
[4] Tri-State has no current plans to exit the Missouri Basin Power Project ("MBPP") – see written information regarding this modeling assumption below.

		○ Member exits ○ Moving WACM load (WY/WNE, WCO and a portion of ECO) to SPP RTO in April 2026 ○ Remainder of ECO load and all NM load to RTO by 2030.
	Modeling of Term Sales	Known and anticipated term sales opportunities are reflected in modeling
	Modeling of Proxy Sales	Anticipated capacity and energy sales opportunities are reflected in modeling
	Generic Resource Availability	The model will be able to select generic resources starting in as soon as 2026, depending on lead time of each technology
	PPA and Contract Information	Updated latest known COD and reflect any updated terms
	SRP Contract	Model based on market optimization
	System Loss Factor	NM region losses are financial; updated ECO, WCO and WY/NE to 3.5%
Demand-Side Management	Demand Response	DR Target (4% of load) modeled for ECO and WCO; Tri-State DR Program Levels selectable for NM and WY
	Energy Efficiency (EE)	EE Targets modeled for ECO and WCO; Achievable-Low NM and Low WY allowed for model to select and updated per Mesa Point 2023 DSM Potential Study[5]
Environmental	Emissions and Water Use Rates	Updated generator emission and water use rates per TS Environmental and eGrid 2021 rates, as applicable. Thermal resource rates were provided by B&V, while rates for innovative technologies were sourced from public resources.
	Emissions Reduction Targets	26% in 2025 36% in 2026 46% in 2027 80% in 2030
	APCD Workbook Inputs and Resource, Market & Contract Emissions Rates	*2005 Emissions Baseline:* Updated to reflect Partial Requirements Contracts and Member Exits
		Market & Contract Emissions Rates:[6] Generator Resource emission rates updated per TS Environmental. Basin Eastern Interconnection contract updated to 2021 eGRID MROW rates; Basin Western Interconnection contract proxy emission rate is updated to LRS rate for 2025 and 2021 eGRID rate for 2026 to 2029. Market purchase and

[5] May 2023 "Addendum to 2020 Demand-Side Management and Energy Efficiency Potential Study."
[6] Settlement Agreement section 3.11.3. "…Tri-State will use published system, region or market rates as applicable and consistent with APCD regulations and guidance for unspecified source market and contract purchases…" and section 3.11.4. "…Tri-State will convene a meeting before the next ERP to discuss the emissions rate for unspecified energy purchases…" That meeting was held on August 16, 2022.

		sales updated to 2021 eGRID RMPA and AZNM rates as applicable.
	Social Cost of Carbon	As of February 2021 IWG[7] @ 2.5% discount rate
	Social Cost of Methane	As of February 2021 IWG @ 2.5% discount rate

Financial

Electric and Gas Forward Curves, and Transport Costs

Tri-State has updated the electric and gas forward curves using Horizons Energy's Spring 2023 Advisory Reference Case results. The Advisory Service provides fundamental analysis of electricity markets. Horizons Energy produces the EnCompass National Database for developing fundamental prices of the electricity markets including fuel and energy throughout North America related to integrated resource planning. Horizons Energy used Henry Hub gas forward prices from Natural Gas Intelligence through December 2023 and then trended forward through 2050. Cheyenne Hub forecasted basis is used for CIG and Waha forecasted basis is used for Waha fuel curves. Horizons Energy electric forward curves are provided for the four WECC areas of Eastern and Western Colorado, New Mexico, and Wyoming. Tri-State forward price curve blends all four areas equally for an average hourly market price through 2050. Monthly forward price curves are modeled in real 2023 dollars.

Figure 1 represents the electric forward curve data in real (2023) dollars for the resource planning period (RPP):



Figure 2 represents the gas forward curve in real (2023) dollars.

[7] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[redacted]

Table 1 summarizes the additional transport costs and forward curves associated with each gas generating unit:

Table 1: Transportation Costs & Fuel Forward Curve for Gas Resources

Existing Gas Plant	[redacted]	Forward Curve
Limon	[redacted]	CIG
Knutson	[redacted]	CIG
Pyramid	[redacted]	Waha
JM Shafer	[redacted]	CIG
Generic Gas Resources – CO & WY	[redacted]	CIG
Generic Gas Resources – NM	[redacted]	Waha

Coal Forward Curve

Tri-State's forward coal prices change at least annually. The coal price forecast, including rail delivery fees (or "freight"), are used in EnCompass and in the final PVRR analysis in UIPlanner. Tri-State updated the Craig coal forward curve in March 2023. [redacted]

[redacted]

[redacted]



[redacted]



Capital Expenditures and Fixed O&M

Tri-State forecasts capital expenditures based on actual planned or expected projects. Tri-State updated its capital expenditure forecast for use in the modeling.

[redacted][9]

[redacted]

Tri-State also reviews historical data for O&M costs and incorporates known changes impacting future O&M costs to produce an annual forecast of O&M costs. Tri-State utilized its O&M forecast to derive a new fixed O&M forecast for use in the modeling.

[redacted]

[redacted]

Variable O&M

The variable O&M (VOM) reflects the latest average VOM calculated by Tri-State Generation Engineering for the units. Use of the most recent average VOM results in [redacted]

[9] Axial Basin and Dolores Canyon solar resources are not yet operational; therefore, no capital expenditures have been forecasted. Initial capital construction cost is reflected in the financial analysis.

[redacted] Other units' average VOM costs remained relatively consistent with values used in previous modeling.

[redacted]

Annual Inflation Forecast

Tri-State's financial planning and analysis team applies an assumed rate of inflation to adequately budget fixed costs and modeled capital and O&M expenditures used in ERP modeling throughout the resource planning period. The escalation rate is 2.5% in 2024, 2.2.% in 2025, 2.30% in 2026 and 2027, and 2.15% thereafter.

Depreciation Costs and Schedules

Depreciation costs and schedules for existing resources were modeled based on Tri-State's 2023 Generation Plant Depreciation Study completed in May 2023. Also see Attachment C-3 of the ERP Report (Attachment LKT-1). Generic resource modeling assumptions, including book life and operating life, can be found in Attachment C-2.

Renewable and Storage Generic Resource Prices – PPAs and Build Transfers

Tri-State's consultant, CDG, updated the forward price curves for generic renewable, and hybrid resource Power Purchase Agreements (PPAs) as well as renewable build-transfer and standalone storage build costs reflect updated capital and operating expense forecasts, Inflation Reduction Act (IRA) tax credit additions and extensions (production tax credits (PTC) and investment tax credits (ITC)), 2020 ERP Phase II pricing, and, for generic wind in Wyoming, the Wyoming $1/MWh "Wind Tax" is included.

Gas Generic Resource Build Prices

In 2023, Black & Veatch (B&V) reviewed and refreshed generic gas pricing assumptions for the ERP. The assumptions can be found in Attachment C-2: Generic Resources Summary.

Innovative Technology Pricing

Per the 2020 ERP Phase I Settlement Agreement,[10] Tri-State added new generic resource types (e.g., Small Modular Reactors, Hydrogen, Molten Salt Long-Term Storage, Iron Air Storage, Geothermal, etc.) with associated pricing and technology assumptions, as identified in Attachment C-2: Generic Resources Summary.

Resource Integration Adder (Ancillary Service Costs)

Integration Adders are modeled to reflect the ancillary service cost for generic resources in the Balancing Authority Area (BAA) operating in each Tri-State planning region. The adders were updated to reflect 2023 pricing and were applied in the modeling are as follows:

PNM (NM):

- No extra intermittent resource specific charges

WACM (WCO, WYO-WNYE, and ECO):

- Wind: Schedule 3 Regulation $0.4293/kW month
- Solar: Schedule 3 Regulation $0.8427/kW month

Discount Rate

Tri-State's weighted average cost of capital (WACC), or discount rate, as of February 2023 was 4.12%. For comparison, Tri-State's WACC was 4.18% in 2020 ERP Phase II and 4.15% in 2020 ERP Phase I.

LRS 2 & 3 Retirement Cost Profile

Tri-State's portion of the fixed O&M and capital expenditures for Laramie River Station (LRS) Units 2 and 3 are reflected in the financial analysis for each scenario as a sunk cost, continuing through each unit's useful life. Given that these costs are a contractual obligation, they are not an avoidable cost in the expansion plan modeling.

Springerville Unit 3 Retirement Cost Profile

Springerville Unit 3 (SPV 3) retirement cost profile reflects the latest estimated calculation of the following [redacted]

- [redacted]
- [redacted]
- [redacted]

The SPV 3 retirement cost profile still does not reflect potential penalties or costs associated with early contract termination, or facilities and operational costs for shared facilities under joint ownership, which could occur under an early retirement scenario, but continue to be unknown at this time.

[10] Section 3.11.15 of Attachment A of the Unopposed Comprehensive Settlement Agreement, filed January 18, 2022 in Proceeding No. 20A-0528E.

Craig Station Decommissioning Cost

The cost for decommissioning Craig Station was updated in the financial modeling, replacing the previous internal estimate with an estimate that reflects a third-party quote. The decommissioning cost was also updated to reflect Tri-State's share of the cost.

Book Life for Generic Li-Ion Batteries, Renewables and Gas

Generic resources' book life assumptions are identified in Attachment C-2. Useful life of existing resources is identified in Attachment C-3.

Third Party Transmission

All available third-party transmission between planning regions, whether network or purchased long term firm point to point transmission, is included in the model and associated sunk costs are included in the financial model. Also included in the dispatch model is the option to purchase:

- up to 133 MW of hourly transmission at PSCO's Open Access Transmission Tariff (OATT) rate as needed for additional transfers from ECO to NM;
- up to 76 MW of third-party transmission at CRSP's OATT rate from ECO to WCO at an incremental cost; and
- up to 100 MW of third-party transmission at PNM's OATT rate from NM to ECO at an incremental cost.

Operational

CRSP Hydro Forecast

Energy and capacity profiles for Colorado River Storage Project (CRSP) contracts through the RPP are at normal levels, for the following regions: CRSP ECO, CRSP NM, CRSP WCO. This assumption is in light of the U.S. Bureau of Reclamation's May 2023 projection[11] for the Colorado River system of a 0% probability of minimum power pool through 2027 along with recent improvements in near term hydro allotments.

Load Forecast

The load assumptions used in the modeling are based on Tri-State's latest finalized long-term load forecast produced in June 2022. The methodology used for load forecasting is outlined in Attachment F of the ERP Report (LKT-1). Adjustments were made to the forecast to reflect Member exits,[12] Partial Requirements contract load reductions, Colorado energy efficiency, system-wide beneficial electrification for the Tri-State system, and member distributed generation.

Member exits assumed include the following:

- United Power exiting May 1, 2024;
- Northwest Rural Public Power District (NRPPD) exiting May 1, 2024; and

[11] https://www.usbr.gov/lc/region/g4000/riverops/crss-5year-projections.html

[12] Paragraph 63 of Decision No. C23-0437, issued in Proceeding No. 20A-0528E, directed Tri-State to "…submit a load forecast that is indicative of anticipated member departures at the time of filing…"

- Mountain Parks exiting February 1, 2025.

Tri-State is no longer planning its system or acquiring resources to serve the load and reliability needs of these three Members, therefore they are not included in the resource plan.

Separate from the gross load forecast, an offset for 280 MW of Partial Requirements[13] load reduction is included in the model. The quantity of Partial Requirements Member MAX selections known at the time of the start of modeling is 163 MW beginning in 2026 and the quantity for MARS selections is 117 MW beginning in 2026. Based on this, the 163 MW MAX selections reduce the system capacity that Tri-State is responsible for by 163 MW, but the 117 MW MARS selection is a capacity reduction at a prorated amount equivalent to the type of intermittent resource selected (modeled as utility-scale solar). Partial Requirements elections reflect May 2021 and May 2022 Open Seasons, excluding Mountain Parks' election.

System-wide beneficial electrification, discussed below, is added to the load forecast, and Colorado energy efficiency targets—which were modeled as a base assumption in every scenario rather than as a selection by the dispatch model—are subtracted from the gross load forecast in modeling every scenario. Member-owned renewable or distributed generation projects are a deduction to gross load in the modeling process.

Beneficial Electrification

Beneficial Electrification (BE) is included in ERP modeling as additional load in the load forecast. An Achievable-Moderate level BE is modeled for all planning regions in all 2023 ERP Phase I scenarios in alignment with the 2020 ERP Phase I Settlement Agreement.[14] The Achievable-Moderate level of BE load is determined by the BE Potential Study (Attachment G-3 of the ERP Report (LKT-1). "Achievable" potential takes into account barriers that hinder consumer adoption of measures and the capability to ramp up BE program activity over time. The BE Potential Study incorporated the following BE technologies and program opportunities: electric building heating measures, electric vehicles and non-road electric vehicles, cooking measures, and electric equipment such as lawn and garden equipment.

The Achievable-Moderate level of potential assumes BE measures are incented at 50% of the incremental cost, resulting in ~668 GWh of cumulative growth on the Tri-State system through 2040 (roughly 4.4% addition to 2040 base gross load). In the ERP financial analysis, the cost of attaining an Achievable-Moderate level of BE is reflective of Tri-State BE staff forecasted expenditures for incentives and program delivery.

Distributed Generation Forecast

Distributed generation (DG) forecast consists of energy and demand forecasts on a project level for Member self-supply options, including Board Policy 115 – renewable distributed generation on Member Systems, Board Policy 119- Community Solar, and Partial Requirements MARS options. Projects are forecasted based on technology type and location with the use of historical load shapes where available.

[13] Partial Requirements Members can select MAX (Firm capacity) or MARS (intermittent resource) options.
[14] Section 3.11.11.

Constraints

See Attachments B-1 and B-2 of the ERP Report (LKT-1).

Level I & II Reliability Metrics

All 2023 ERP scenarios were modeled to achieve the minimum Level I and II Reliability Metrics identified in the ERP Report (LKT-1).

Thermal Build Constraint

No new thermal builds allowed until 2028 due to infeasibility of engineering, procurement, construction, and permitting completion prior to 2028.

Gas Retirement Constraint

Gas and oil units, including those with dual-fuel capability available for contingency operations are not allowed to retire in the modeling given that they are necessary for maintaining reliability. These units operate during extreme weather events, support market price arbitrage to reduce costs, support reliability during coal unit outages, and can offer surplus interconnection benefits for co-located renewable resources.

Coal Unit Uptime

Minimum run-time for all coal units was set to 12 hours in the modeling, reflective of a May 2020 report[15] by the Western Electricity Coordinating Council (WECC).

Coal Unit Downtime

Minimum down-time for all coal units was set to 8 hours in the modeling, reflective of a May 2020 report[16] by the WECC.

Craig 3 Modeling

Per the 2020 ERP Phase I Settlement Agreement,[17] Tri-State modeled Craig 3 in the ECON designation, allowing the model to economically commit and dispatch the unit subject to the minimum up and down times.

Craig Unit Retirements

Craig Units 1 and 2 retirements are modeled to occur on the announced dates; and Craig Unit 3 is modeled to allow the unit's retirement between January 1, 2028 and December 31, 2029, except where otherwise modeled per unique scenario assumptions (see Attachment B-3: Unique Scenario Assumptions of the ERP Report (LKT-1)). Craig Unit 3 is not allowed to retire prior to January 1, 2028 in the modeling to ensure sufficient lead-time for the community transition between completion of the 2023 ERP and the earliest potential retirement date and to allow sufficient time for replacement resources to be secured. Craig Unit

[15] *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council*, May 12, 2020; Table 2, page 21 (720 minutes Minimum Up Time for coal units). Available: 1r10726 WECC Update of Reliability and Cost Impacts of Flexible Generation on Fossil.pdf.
[16] *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council*, May 12, 2020; Table 2, page 21 (480 minutes Minimum Down Time for coal units). Available: 1r10726 WECC Update of Reliability and Cost Impacts of Flexible Generation on Fossil.pdf.
[17] Section 3.6.6.

3 is not allowed to retire later than December 31, 2029 given that date is the publicly announced retirement date for the unit as identified in Colorado Regulation No. 23 Regional Haze Limits.

Tri-State Exit MBPP

Tri-State has no current plans to exit the Missouri Basin Power Project ("MBPP"). Tri-State is an MBPP participant and receives a portion of Laramie River Station (LRS) generation and transmission through its share of the MBPP contract. Tri-State is only a partial owner of LRS, therefore any "LRS early retirement" modeling simulates Tri-State exit of the MBPP Agreement, not retirement of the unit. This assumption is applied to be informative to the resource plan modeling.

SPV 3 Retirement

SPV 3 is allowed to retire beginning January 1, 2037, upon the conclusion of the 100 MW third-party supply contract (Fall 2036), except where otherwise modeled per unique scenario assumptions (see Attachment B-3 of the ERP Report (LKT-1)).

SPV 3 Max Capacity

In July 2022, a capacity test was conducted affirming the previous maximum capacity rating for SPV 3 of 419 MW.

Effective Load Carrying Capability

ELCCs were updated for wind, solar, storage, coal, and gas resources for the 2023 ERP based on the third-party study completed in August 2023. The ELCC methodology and study results are provided in Attachment G-1 of the ERP Report (LKT-1). For capacity expansion modeling, firm capacity of each unit reflects the Equivalent Forced Outage Rate (eFOR) by unit identified in *Table 18. TSGT UCAP Capacity* of Attachment G-1 of the ERP Report (LKT-1).

Scheduled Outages

The following identifies the scheduled outages modeled for coal units during the RAP.

Table 4: Scheduled Coal Unit Outages During the RAP

[redacted]

Forced Outage Factors

Dispatch plan modeling reflects the average FOFs by unit,[18] as shown in Table 5.

Table 5: Thermal Unit Forced Outage Factors (FOFs)

Unit	5-yr Average FOF (%)
Craig 1	4.00
Craig 2	2.05
Craig 3	13.89
LRS 2	6.49
LRS 3	7.18
SPV3	5.78
Burlington 1	0.99
Burlington 2	0.53
Knutson 1	1.98
Knutson 2	0.72
Limon 1	0.67
Limon 2	0.33
Pyramid 1	0.19
Pyramid 2	1.24
Pyramid 3	0.44
Pyramid 4	0.95
JM Shafer	4.71

These FOF factors were developed using five years of historical FOFs data from 2018-2022, shown in Table 6.

Table 6: Historical Thermal Unit FOFs

Unit	2018	2019	2020	2021	2022
Craig 1	5.53	1.21	3.35	8.18	1.75
Craig 2	0.27	2.18	0.99	2.17	4.65
Craig 3	45.24	3.39	3.67	4.36	12.78
LRS 2	6.33	2.20	7.82	12.71	3.39
LRS 3	0.01	0.51	10.34	23.47	1.56
SPV3	7.77	9.09	1.41	7.8	2.82
Burlington 1	2.46	0.70	0.43	1.34	0
Burlington 2	0.67	0.32	0.35	0.87	0.45
Knutson 1	0.33	0.89	0.22	0.03	8.45
Knutson 2	0.21	0.66	1.55	0.4	0.77
Limon 1	1.71	0.29	0.06	0.01	1.29

[18] The input field in EnCompass is FOR.

Unit	2018	2019	2020	2021	2022
Limon 2	0.45	0.57	0.12	0.45	0.07
Pyramid 1	0.27	0.35	0.02	0.02	0.31
Pyramid 2	2.76	0.07	0.39	0	2.97
Pyramid 3	0.26	0.97	0.91	0.08	0
Pyramid 4	0.26	2.41	0.18	1.88	0
JM Shafer	5.04	13.13	1.46	2.12	1.8

EnCompass randomly selects for each day how many individual units will be forced out due to operational failure. This random selection is based on the FOR and Random Outage Seed inputs. The model uses the FOR to determine the number of full forced outage days per year and will randomly select the dates in each year.

Modeling of Market Sales and Purchase Depths

All market purchases and sales are transacted at a regional level trading hub within the model. Market depths in 2024 are reflective of Member exits, and access to existing Western Energy Imbalance Market (WEIM) and Western Energy Imbalance Service (WEIS) markets. Market depths beginning in 2026 are reflective of the WACM BA moving to SPP RTO. Additional market depth in ECO is added in 2030 reflective of an assumption that PSCo will be in an RTO by 2030. Market depths in New Mexico are reflective of assumptions that PNM joins an RTO by 2030. The tables below show the market depths as modeled.[19]

Table 7: Market Sales Characteristics

Market	2024-March 2026	April 2026-2029	2030-
	ATC (MW)	ATC (MW)	ATC(MW)
ECO	200	250	300
WCO	100	200	200
NM	75	75	150
WYO-WNE	100	200	200

Table 8: Market Purchase Characteristics

Market	2024-March 2026	April 2026-2029	2030-
	ATC (MW)	ATC (MW)	ATC (MW)
ECO	150	200	200
WCO	100	200	200
NM	100	100	200
WYO-WNE	75	200	200

Tri-State currently meets its contingency reserve requirements through its membership in the Southwest Reserve Sharing and two sub-entity Reserve Sharing Group agreements. Modeling includes contingency

[19] Market sales were reviewed by a third-party consultant in May 2023.

reserve requirements for these existing reserve sharing groups. Potential regulation and contingency reserve sales opportunities within the SPP RTO are not reflected in the Phase I modeling.[20]

Modeling of Short & Long-Term Sales

Modeling reflects existing term sales as follows:

- **City of Farmington Sale** (Modeled as a Term Sale)**:** 25 MW per hour maximum on-peak capacity; 15 MW per hour maximum off-peak capacity ~181 GWh/year in energy sales. Effective date 7/1/23; contract expires 12/31/25.
- **DOE National Nuclear Security Administration Sale** (Modeled as a Term Sale)**:** Up to 40 MW capacity, ~351 GWh/year in energy sales. Contract is effective from 1/1/24-12/31/25.
- **SRP Sale:** SPV 3 located in Arizona, 100 MW (Maximum Capacity) ~375 GWh/year. Effective Date 10/20/2003; Contract Expires 8/31/2036. In some of the modeled scenarios, Springerville 3 is retired before the end of the contract date. Tri-State cannot terminate operations of Springerville 3 and the related third-party contract without reaching agreement with impacted parties.

Modeling of Proxy Sales

Tri-State modeled proxy sales for near-term years in anticipation of the ability to sell excess power upon Member exits. Proxy sales include:

- [redacted]
- [redacted]

In September 2023, Tri-State issued a reverse RFP and resulting potential sales are still under evaluation with some negotiations in progress.

Generic Resource Availability

The model is able to select generic resources to be added in the expansion plan starting as soon as 2026, depending on lead time of each technology as identified in Attachment C-2 of the ERP Report (LKT-1).

PPA and Contract Information

Modeling reflects PPA capacity, energy, and CoDs shown in Attachment C-1 of the ERP Report (LKT-1). Tri-State's modeling reflected known PPA updates, including:

- Escalante Solar commercial operation date (COD) was advanced from December 2024 to June 2024 based on updated project schedule. Escalante Solar was modeled through December 2043, the end of the Resource Acquisition Period.
- Axial Basin and Dolores Canyon are no longer PPAs and were modeled as Tri-State owned resources.[21]

[20] Tri-State is evaluating the potential to model these opportunities in Phase II of the 2023 ERP.
[21] See Attachment C-3 of the ERP Report (LKT-1). Also see Proceeding No. 23A-0548E.

After scenario modeling began, additional PPA changes occurred:

- Due to global supply chain and tariff uncertainties impacting construction schedules, the Coyote Gulch Solar PPA was terminated, effective October 1, 2023.[22]
- Additionally, due to similar reasons noted above, the price increased from [redacted] for the Spanish Peaks and Spanish Peaks II PPAs. Simultaneous to the price modification, the Spanish Peaks and Spanish Peaks II PPAs were also extended for four additional years, from a 2039 contract end date to 2043 (making them 19-year PPA terms).[23]

SRP Contract

Salt River Project (SRP) is assumed to take at least the contract minimum capacity amount from SPV 3, but if the cost of SPV 3 energy is lower than forecasted market prices, the SRP take can be modeled above the contract minimum, up to the max contract capacity (100 MW).

System Loss Factor

The transmission system loss factor is meant to represent an average of expected transmission losses as Tri-State load in the Western Interconnection is located across multiple BAs and Transmission Provider systems. The transmission loss factor used in the planning and dispatch models was 3.5% in the Wyoming, Western Colorado, and Eastern Colorado planning regions. A portion of transmission system losses are financial, and are recorded in the financial models as a purchase power expense.

Demand-Side Management

Demand Response

For the ECO and WCO planning regions, Tri-State models achievement of the "DR Target." The DR Target[24] requires Tri-State to "…develop in-house demand response offerings in Colorado by 2025 that are designed to control at least 4% of Tri-State's Colorado peak load." Tri-State bases its DR modeling on the programs it anticipates launching, which include controls for: water heaters and air conditioners for residential and small commercial settings, irrigation load, and commercial and industrial (C&I) applications. Tri-State also models Low DR for WYO-WNE and NM planning regions,[25] which is generally consistent with internally-forecasted levels of uptake of DR programs.

Modeling the DR Target for ECO and WCO involves the following input assumptions and parameters:

- DR Target of at least 4% MW is a must-take, not a selection in the model.
- There are five different "DR resource" types: (1) Commercial & Industrial (C&I), (2) Irrigation, (3) Residential Battery Energy Storage Systems (BESS), (4) Residential Air Conditioning (A/C), and

[22] The Coyote Gulch Solar PPA was cancelled subsequent to initiation of Phase I scenario modeling, and therefore was included in the modeling, with a July 2026 COD. Replacement capacity will be procured through 2023 ERP Phase II.
[23] These contract modifications occurred subsequent to initiation of Phase I scenario modeling.
[24] See 2020 ERP Phase I Settlement Agreement, section 3.11.8.
[25] "Low DR" is based on the DSM and EE Potential Study completed by MesaPoint Energy for the 2020 ERP, May 8, 2020.

18(5) Residential Water Heaters (WH). Each has different values for Max Capacity, Maximum Daily Energy, Maximum Annual Energy, and Payback Required.

- **Max Capacity** sets the daily maximum output for each DR resource;
- **Maximum Daily Energy (%)** sets the maximum capacity factor for each day, limiting daily output to this input capacity factor;
- **Maximum Storage (MWh)** sets the maximum amount of energy that can be stored at any given time; and
- **Maximum Annual Energy (%)** sets the maximum capacity factor for the year.
- **Payback Required (%)** sets the percentage rate at which the interrupted load requirements need to be replaced.

- DR resource costs assumed for meeting the DR Target for ECO and WCO, both programmatic and incentive costs, are included in each scenario's financial analysis (i.e., revenue requirements), applied across the "lifetime" of the DR resources. The costs were provided by Tri-State's DSM department.

DR is dispatched by the model by determining the most economical way to dispatch DR thus shifting load while adhering to the hourly constraints and payback requirements in a given hour, day, and season. For example, the C&I DR resource is able to be called on year-round, but only during hours 8-16 (nine hrs/day) up to 14.5 MW in 2030, but only up to 8.6 GWh/yr (6.8% of annual capacity), and only can dispatch six of the nine hours in a given day (6/24 = 25% of Maximum Daily Energy). Also, DR resources are modeled like a battery in that whatever demand energy is curtailed, some amount of payback is required. In the case of the C&I DR resource, a 50% payback is required, so, for example, in year 2030 if it curtails 8.6 GWh/yr, 4.3 GWh/yr is paid back.

Modeling DR resources for WYO-WNE and NM involves the following input assumptions and parameters:

- DR resources can be selected by the model for WYO-WNE and NM.
- All of the five DR resources together are one Project in Encompass with an associated capital cost (CapEx) based on the present value of the lifetime expenditures for that project. If the Project is the most economic choice for meeting system load needs then the Project is selected and the associated Capex is modeled as an expenditure and the DR resource parameters (Max Capacity, etc. noted above) are applied in the modeling.
- The costs associated with the selected DR resources for WYO-WNE and NM, both the programmatic and incentive costs, are included in each scenario's financial analysis (i.e., revenue requirements) applied across the "lifetime" of the DR resources. The costs were provided by Tri-State's DSM department.

Because much of DR reflects shifts in the time periods when energy is used, financial models – which focus on energy billed to members within a month – show DR energy impacts net of timing shifts.

Energy Efficiency

ECO and WCO regions were modeled to achieve the EE Targets[26] of 0.35% in 2023, 0.5% by 2024, 0.75% by 2025, and 1% by 2030 in incremental annual energy efficiency savings for Colorado Utility Member

[26] *See* 2020 ERP Phase I Settlement Agreement, Section 3.11.9.

system load.[27] See table below for estimated energy equivalents for EE Targets based on the latest load forecast.[28] WYO and NM regions were allowed to select Achievable-Low EE[29] starting in 2025.

Table 9: Colorado Energy Efficiency Targets and GWh Equivalent

Target Year	EE Target (%)	Est. GWh Equivalent
2023	0.35%	39.0
2024	0.50%	145.6
2025	0.75%	59.0
2030	1.00%	73.4

Environmental

Emission and Water Use Rates

Emission rates (lbs/MWh) and water use (gal/MWh)[30] for existing units were updated based on 2022 actual emissions, water use, and net generated MWh for each generator. Emissions rates and water use for generic thermal resources were reviewed and updated by B&V in Spring 2023. Emission rates and water use for innovative technologies were based on industry research and developer specs, where available. Emission and water use rates used for 2023 ERP Phase I modeling are shown in the table below. Also see Attachment C-2 of the ERP Report (LKT-1).

Table 10: Emission and Water Use Rates

	CO_2	SO_2	NOx	Hg	PM	VOC	Water Usage
UNIT	lbs per Net MWh	lbs per Net MWh	lbs per Net MWh	lbs per Gross MWh	lbs per Gross MWh	lbs per Gross MWh	(gal/MWh)
LRS 2	2489	1.414	1.693	0.00001	0.126	0.0325	685
LRS 3	2489	1.414	1.693	0.000	0.126	0.0325	685
Craig 1[31]	2388	0.604	2.790	0.0000040	0.104	0.0021	573
Craig 2	2388	0.526	0.801	0.0000038	0.117	0.0019	573
Craig 3	2204	1.332	2.240	0.0000065	0.040	0.0299	573
Springerville 3	2372	0.990	0.857	0.0000043	0.196	0.0325	548

[27] There were two minor inputs to energy efficiency that were incorrectly reflected in calculation of Colorado load for purposes of determining EE Targets in the modeling: 1) Partial Requirements deductions from total load started in 2025 instead of 2026; and 2) deductions for *all* Partial Requirements member elections were deducted from Colorado load requirements for purposes of calculating energy efficiency in the modeling, but should not have included non-Colorado partial requirements. The magnitude of this impact is immaterial, at less than a tenth of a percent.

[28] Page 27 of Tri-State's informational DSM plan filed in Proceeding No. 20A-0528E on September 1, 2022 contained EE Targets forecasted based on Tri-State Colorado system load at that time.

[29] Attachment G-3 of the ERP Report (LKT-1).

[30] Pursuant to Rule 3605(a)(IV)(I).

[31] NOx limits for Craig 1 are in place to comply with the Colorado State Implementation Plan related to the Regional Haze rule.

	CO_2	SO_2	NOx	Hg	PM	VOC	Water Usage
UNIT	**lbs per Net MWh**	**lbs per Net MWh**	**lbs per Net MWh**	**lbs per Gross MWh**	**lbs per Gross MWh**	**lbs per Gross MWh**	**(gal/MWh)**
Burlington 1	2121	0.063	10.633	*N/A*	0.145	0.0050	10
Burlington 2	2121	0.063	10.895	*N/A*	0.149	0.0051	10
Pyramid 1	1232	0.010	1.394	*N/A*	0.074	0.0213	40
Pyramid 2	1232	0.008	1.127	*N/A*	0.068	0.0205	40
Pyramid 3	1232	0.017	1.285	*N/A*	0.079	0.0184	40
Pyramid 4	1232	0.009	1.147	*N/A*	0.070	0.0207	40
Limon 1	1594	0.009	0.294	*N/A*	0.067	0.0026	32
Limon 2	1594	0.011	0.387	*N/A*	0.079	0.0028	32
Knutson 1	1515	0.011	0.387	*N/A*	0.118	0.0008	17
Knutson 2	1515	0.010	0.329	*N/A*	0.118	0.0008	17
J. M. Shafer	985	0.005	0.725	*N/A*	0.053	0.0465	343
Unspecified Energy Purchases	**Years 2023 - 2029**						
Basin Nebraska	996	0.981	0.822	*N/A*	*N/A*	*N/A*	*N/A*
Basin Electric- CO/WY thru 2025	2596	1.299	1.443	*N/A*	*N/A*	*N/A*	*N/A*
Basin Electric- CO/WY 2026-2029	1159	1.299	1.443	*N/A*	*N/A*	*N/A*	*N/A*
Market Purchases	1159	0.344	0.591	*N/A*	*N/A*	*N/A*	*N/A*
Energy Imbalance	1159	0.344	0.591	*N/A*	*N/A*	*N/A*	*N/A*
Gas Expansion Plan Units							
46_5x9RICE	981	0.010	0.180	*N/A*	0.042	0.089	0
40_1x40LM6000	1089	0.011	0.084	*N/A*	0.069	0.027	40
200_1x235_7FA05	1165	0.012	0.090	*N/A*	0.073	0.029	57
Natural Gas CCS	765	0.008	0.046	N/A	0.048	0.019	348
Innovative Tech - Expansion							
Blue Hydrogen w/CCS	59		0.19				570
Green Hydrogen	0		1.06				357
Nuclear SMR	N/A						672
Geothermal EGS/Adv	N/A						100
Non-Emitting Technology with Water Usage	*Note:* Net battery generation is negative; the negative water usage, when applied to negative generation, results in positive overall water usage for non-emitting technology with water usage.						
10 Hour Battery	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	0
Battery - Iron Air	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	-24.7
Molten Salt Storage	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	-51
Pumped Hydro	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	*N/A*	-412

Emissions Reduction Targets

All portfolios are modeled to achieve at least the Interim-Year Emissions Reductions and 2030 Emissions Reduction Targets.[32] Also see Attachment B-3 of the ERP Report (LKT-1).

APCD Workbook Inputs and Resource, Market & Contract Emissions Rates

As shown in Attachments D1-D5 to the ERP Report (LKT-1), the APCD Workbooks for each scenario, Tri-State's 2005 carbon emissions baseline reflects adjustments necessary to exclude Member Exits and Partial Requirements contracts from the baseline in relevant years. Details regarding Member Exits and Partial Requirements are described above, see *Load Forecast*.

Additionally, market and contract emissions rates were updated as follows:

- Basin Eastern Interconnection contract updated to 2021 eGRID MROW rates;
- Basin Western Interconnection contract updated to LRS emission rates for 2025, and 2021 eGRID RMPA rate for 2026 to 2029; and
- Market purchase and sales updated to 2021 eGRID RMPA and AZNM rates as applicable.

Social Cost of Carbon

Social Cost of Carbon ("SCoC") is based on the latest values published by the Interagency Working Group (IWG) on the Social Cost of Greenhouse Gases, for calculating the net present value of carbon dioxide emissions, brought back to present value with a 2.5% discount rate.[33] The values, which are in 2020 real dollars, are inflated using the inflation rate assumptions used throughout the ERP.

Social Cost of Methane

Social Cost of Methane ("SCoM") is based on the latest values published by the IWG on the Social Cost of Greenhouse Gases, for calculating the net present value of methane emissions, brought back to present value with a 2.5% discount rate.[34] The values, which are in 2020 real dollars, are inflated using the inflation rate assumptions used throughout the ERP.

[32] See 2020 ERP Phase I Settlement Agreement, Sections 3.3.4 and 3.3.5.
[33] The IWG has not published an update to SCoC values or the discount rate since February 2021.
[34] The IWG has not published an update to SCoM values or the discount rate since February 2021.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-89:
Tri-State 2025 ERP Annual Progress Report

Colorado PUC E-Filings System



Tri-State Generation and Transmission Association, Inc.

2025 Annual Progress Report

2023 Electric Resource Plan

Colorado Public Utilities Commission
Proceeding No. 23A-0585E

December 1, 2025

Forward-Looking Statement

Forward-looking statements include statements concerning our plans, objectives, goals, strategies, future events, future revenue or performance, forecasts, including load, energy, resources, and commodities, future capital expenditures, capacity needs, plans or intentions relating to development, acquisition, operation, or closure of facilities, in-service dates of facilities, emission reductions, demand response targets, energy efficiency targets, Member withdrawals, business trends or business strategy and other information that is not historical information. When used in this Annual Progress Report, the terms "estimates," "expects," "anticipates," "projects," "plans," "intends," "believes" and "forecasts" or future or conditional verbs, such as "will," "should," "could" or "may," and variations of such words or similar expressions, are intended to identify forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties, and assumptions, including those described in our filings with the Securities and Exchange Commission. All forward-looking statements, including, without limitation, management's examination of historical operating trends and data, are based upon our current expectations and various assumptions. These expectations and beliefs are expressed in good faith grounded in a reasonable basis. However, we cannot guarantee 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 in this Annual Progress Report.

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3. Updated Evaluation of Planning Reserve Margins and Contingency Plans 8
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Introduction

Tri-State Generation and Transmission Association, Inc. ("Tri-State") filed Phase I of its 2023 Electric Resource Plan ("ERP" or "Resource Plan") with the Colorado Public Utilities Commission ("Commission") on December 1, 2023 in Proceeding No. 23A-0585E. At the time of this report, Phase II resource acquisitions remain ongoing, pursuant to Decision No. C25-0612. In compliance with Commission Rule 3618(a), Tri-State submits the following Annual Progress Report ("APR") on its efforts under its electric resource plan.

As discussed below, Tri-State is forecasting a need for 19 MW of additional generation capacity by summer 2035.[1] This forecast incorporates existing resources, 2023 ERP Phase II preferred portfolio resources, and planned unit retirements.

This 2025 APR contains the following sections, in compliance with Commission Rule 3618(a):

A. An updated annual electric demand and energy forecast;
B. An updated evaluation of existing resources;
C. An updated evaluation of planning reserve margins and contingency plans;
D. An updated assessment of need for additional resources;
E. An updated report of the utility's action plan and resource acquisitions; and
F. An explanation of Tri-State's efforts to give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions.
G. An update on Tri-State's progress toward its GHG emissions reduction targets.

The intent of the APR is to discuss material changes in assumptions, fleet characteristics, load forecasts and other factors that have occurred since the 2024 APR and 2023 ERP Phase II were filed. To the extent issues addressed in Tri-State's 2024 APR or 2023 ERP Phase I and Phase II filing have not materially changed, they are not addressed herein.

[1] 2024 APR: 11 MW need projected stating in 2030
2023 ERP: 68 MW need projected starting in 2029
2022 APR: 126 MW need projected starting in 2030
2021 APR: 248 MW need projected starting in 2030
2020 ERP: 95 MW need projected starting in 2029
2019 APR: 70 MW need projected starting in 2027
2018 APR: 115 MW need projected starting in 2026
2017 APR: 148 MW need projected starting in 2026
2015 ERP: 9 MW need projected starting in 2023

Tri-State has made several changes to its resource portfolio in recent years reflecting increasing amounts of renewable resources and lower emissions trajectory, notably:

- Craig Unit 1[2] is planned to cease operations by December 31, 2025, Craig Unit 3 will retire January 1, 2028, and Craig Unit 2[3] will retire by September 30, 2028.
- Springerville Unit 3 ("SPV 3") is planned to cease operations by March 1, 2031.[4]
- Two solar projects came online in 2024 in Colorado, Spanish Peaks Solar (100 MW) and Spanish Peaks II Solar (40 MW) in Las Animas County.
- Two solar projects came online at the end of October 2025 in Colorado, Axial Basin Solar (145 MW) in Moffat County and Dolores Canyon Solar (110 MW) in Dolores County.

1. Updated Annual Electric Demand and Energy Forecast

Commission Rule 3618(a)(I)

Tri-State's most current demand and energy forecast was modeled in 2023 ERP Phase II and no subsequent revisions have been made. The forecast reflected in Table 1 represents Tri-State's System Wide annual energy and seasonal peaks as modeled in 2023 ERP Phase II. Subsequent to the commencement of modeling in Phase II, Tri-State received notice from the Northwest Rural Public Power District in Nebraska ("NRPPD") that it intends to depart Tri-State Utility Membership on January 1, 2027. NRPPD is served solely in the Eastern Interconnection through an all requirements contract, and NRPPD's departure does not impact Tri-State's electric demand and energy forecast for purposes of Tri-State's Colorado ERP. [5]

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[2] Tri-State's ownership share is 102 MW (24%) of this unit, which has a total nameplate capacity of 427 MW.
[3] Tri-State's ownership share is 98 MW (24%) of this unit, which has a total nameplate capacity of 410 MW.
[4] Decision No. R24-0602 found that a retirement date of September 15, 2031 for SPV 3 was reasonable contingent upon Tri-State receiving a New ERA funding award and successful negotiation of contractual agreements impacted by the unit's retirement. The New ERA award is contingent upon a March 1, 2031 retirement date for SPV 3, consistent with the requirement for USDA to disperse all New ERA funds by September 30, 2031.
[5] *See* Attachment B to Tri-State's Phase II Implementation Report, filed April 11, 2025 in Proceeding No. 23A-0585E.

TABLE 1 – 10-YEAR DEMAND AND ENERGY FORECAST

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Sales (GWh)	13,051	13,110	13,455	13,642	13,830	14,049	14,289	14,521	14,773	15,036
Winter Peak Demand (MW)	1,865	1,739	1,778	1,825	1,847	1,888	1,886	1,955	1,998	2,038
Summer Peak Demand (MW)	2,344	2,423	2,454	2,431	2,472	2,535	2,583	2,635	2,646	2,629

2. Updated Evaluation of Existing Resources

Commission Rule 3618(a)(II)

Figure 1 below depicts the sources of generation serving Tri-State's 2024 total energy sales. Figure 2 below depicts Tri-State's 2024 capacity by generation source. Tri-State's assessment of its existing resources remains the same as what was presented in Tri-State's 2023 ERP Phase I.

FIGURE 1 – 2024 ENERGY MIX, GROSS SALES

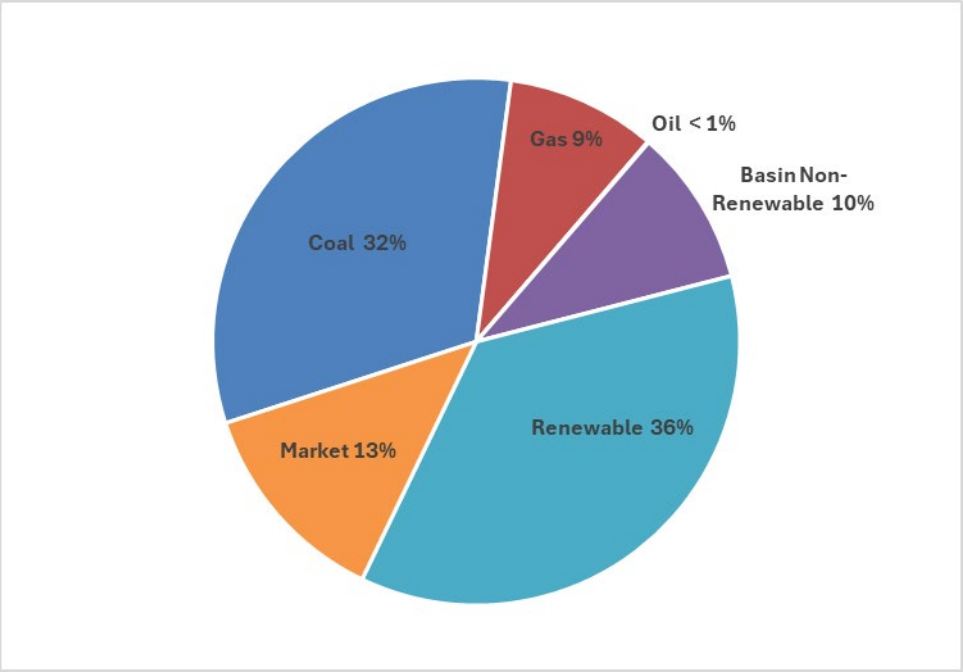
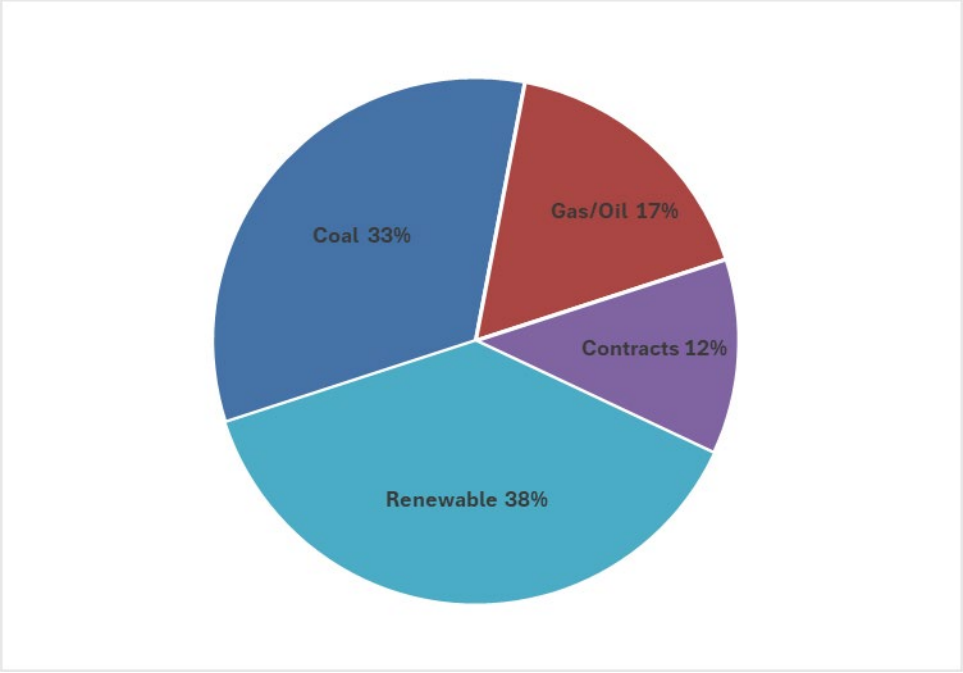


FIGURE 2 – 2024 CAPACITY PORTFOLIO



3. Updated Evaluation of Planning Reserve Margins and Contingency Plans

Commission Rule 3618(a)(III)

There are no updates or changes to the planning reserve margin ("PRM") or contingency plans from those contained in Tri-State's 2023 ERP Phase I or Phase II filing.[6] Tri-State continues to base its resource plans on a 22% PRM until the retirement of Craig Unit 3, after which the PRM increases to 30.5% beginning in 2028. Tri-State's participation in reserve sharing agreements and bilateral hazard-sharing arrangements provide additional support for reliable operations.

Tri-State continues to plan for its WACM load and resources to enter the Southwest Power Pool ("SPP") RTO in April 2026. Once in the RTO, Tri-State's assets in the WACM BA authority will be subject to SPP's PRM requirements. Tri-State is evaluating the SPP PRM requirements and will compare them to Tri-State's most recent PRM requirement. Tri-State intends to follow the more stringent of the two PRM requirements for its system planning.[7]

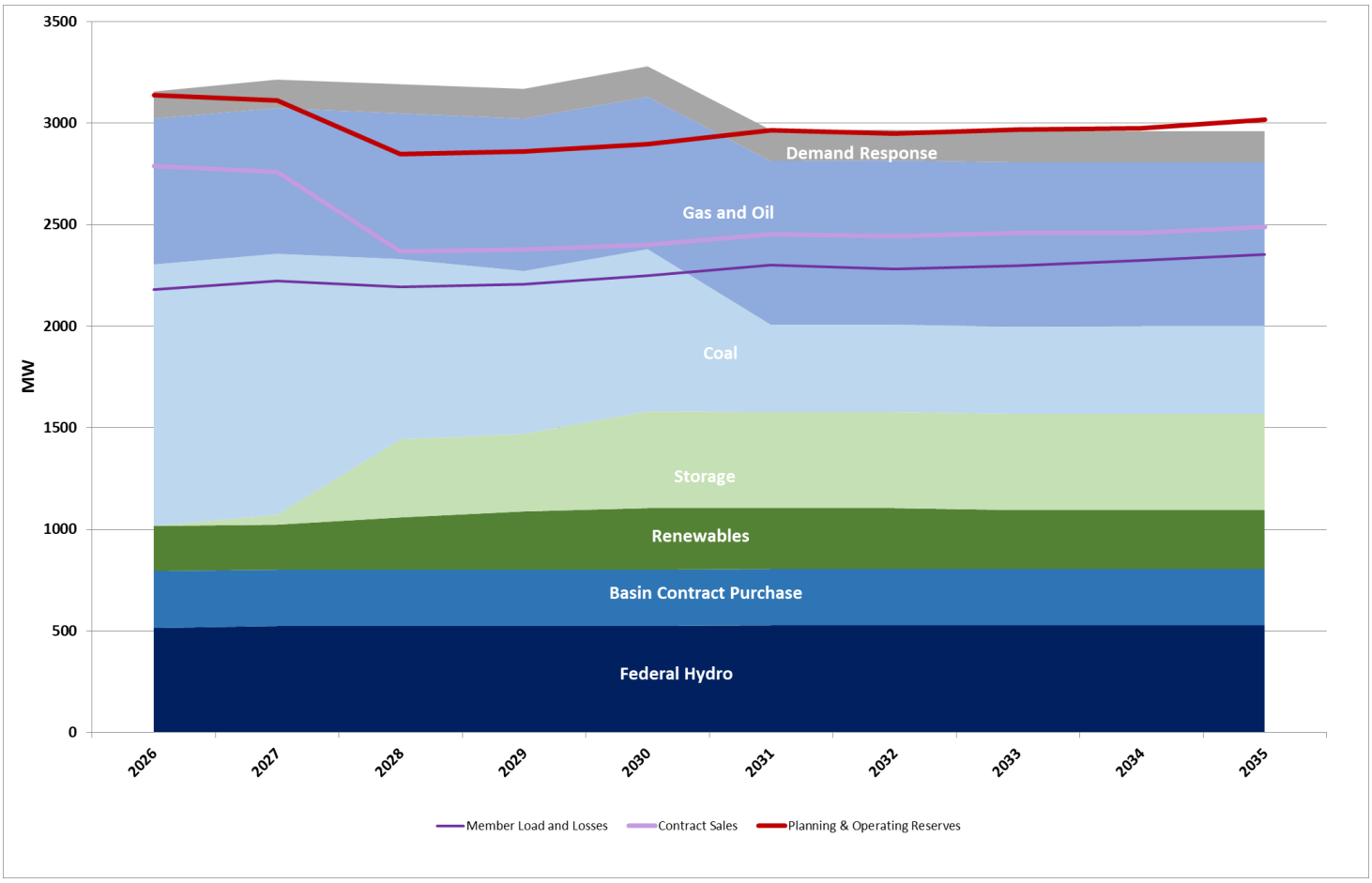
4. Updated Assessment of Need for Additional Resources

Commission Rule 3618(a)(IV)

Tri-State stated within Phase I of the 2023 ERP that it did not forecast a capacity shortfall until 2029. With the updated load forecast, shown above, utilized in Phase II and Phase II preferred portfolio resources, a capacity shortfall is not forecasted to occur until 2035, as shown in Figure 3 and Table 2 below. Tri-State's electrically east load is supplied by a full requirements contract with Basin Electric Power Cooperative and is not included in the load or resource portion of Figure 3 and Table 2.

[6] LKT-1 - Attachment G-1 - Confidential - ELCC and PRM Study (Astrape) filed December 1, 2023 in Proceeding No. 23A-0585E.
[7] Response Comments of Tri-State Generation and Transmission Association, Inc., Proceeding No. 25A-0266E.

FIGURE 3 –LOAD AND RESOURCES



The data for Figure 3 is shown in Table 2.

TABLE 2 – LOAD AND RESOURCES

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Federal Hydro	516	524	523	524	525	527	527	527	527	527
Contract Purchases	278	278	278	278	278	278	278	278	278	278
Renewables[8]	224	221	259	285	303	299	299	290	291	291
Demand Response	134	141	144	147	149	151	152	153	154	155
Coal Generation[9]	1287	1286	888	800	431	431	432	431	432	431
Gas & Oil Generation[10]	717	717	717	751	751	806	806	806	806	806
Storage[11]	0	49	383	383	474	474	474	474	474	474
Total Resources	3155	3215	3193	3169	3280	2965	2967	2959	2961	2961
Member Load and Losses[12]	2180	2223	2195	2206	2249	2302	2282	2297	2323	2355
Planning & Operating Reserves	350	351	478	482	495	511	505	509	517	527
Contract Sales	608	536	173	173	151	151	162	162	135	135
Total Obligations	3138	3110	2846	2861	2895	2964	2949	2968	2976	3017
Excess Resources	8	89	372	335	412	30	46	19	22	-19

5. Updated Report of the Utility's Action Plan and Resource Acquisitions

Commission Rule 3618(a)(V)

Tri-State's 2023 ERP Phase II procurement process is underway. Bids were received on October 28, 2024, in response to three Phase II requests for proposals.[13] A summary of bids was filed in Proceeding No. 23A-0585E on December 12, 2024;[14] and bids selected in the Phase II preferred portfolio were identified in Tri-State's ERP Implementation Report filed April 11, 2025. Tri-State has 500 MW of preferred portfolio storage resources under contract, 200 MW of preferred portfolio wind resources under contract, and is continuing contracting efforts for other preferred

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8 Capacity is based on applying the effective load carrying capability by renewable technology to the nameplate of renewable resources.

9 Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.

10 Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.

11 Capacity is based on applying the effective load carrying capability for storage to the nameplate of storage resources.

12 Western Interconnection Load.

13 Bids for the Dispatchable RFP were received November 27, 2024.

14 *See* Tri-State's 45-Day Report filed in Proceeding No. 23A-0585E.

portfolio resources, including evaluation of back-up bids as needed. The preferred portfolio bids under contract include:

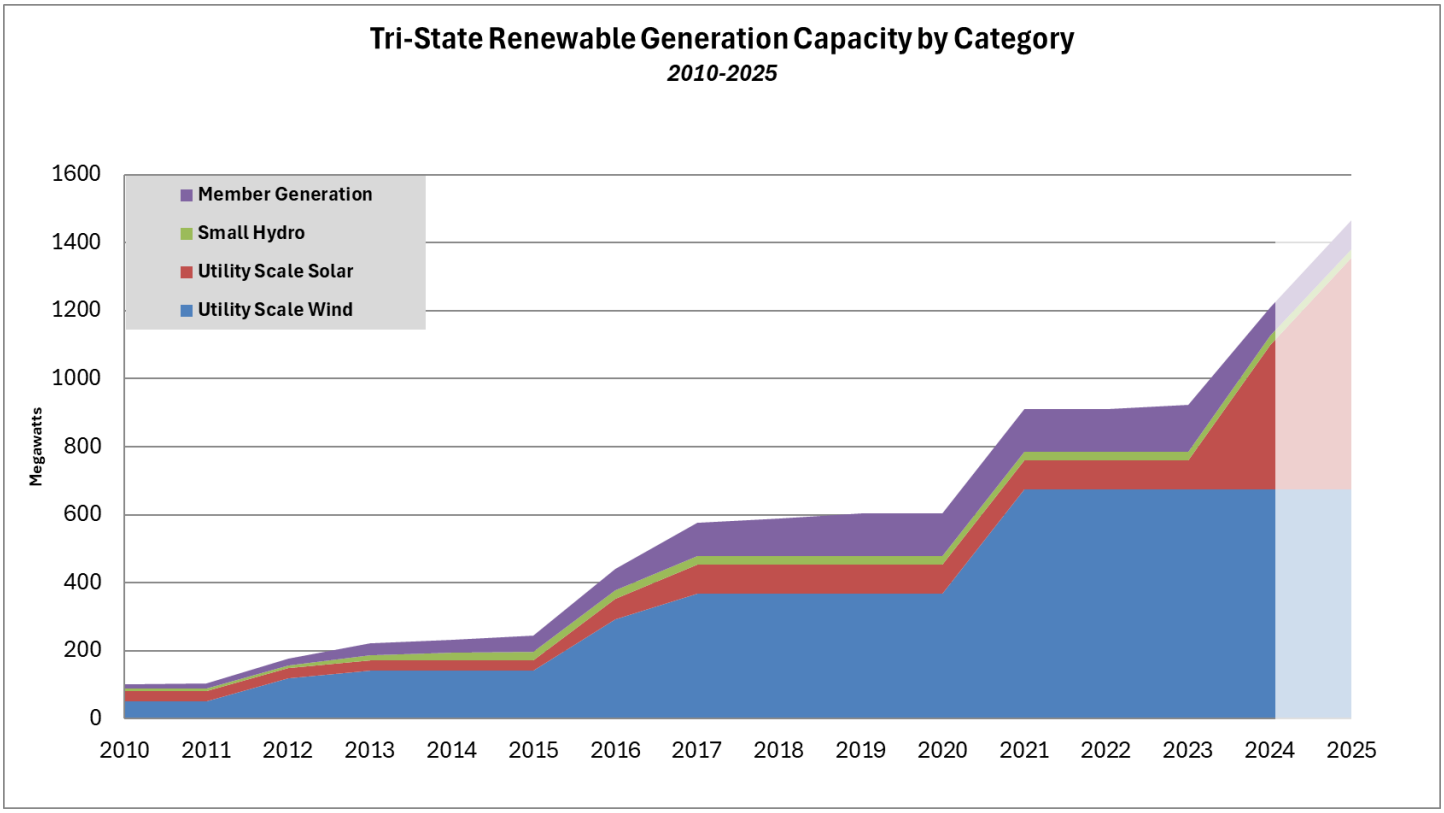
- High Country Energy Station 2 (Montrose County, CO), 50 MW, Q2-2027 COD;
- Oso Negro Energy Storage (Bernalillo County, NM), 100 MW, Q2-2028 COD;
- Morel Energy Storage (Moffat County, CO), 200 MW, Q1-2030 COD;
- Carousel Energy Storage (Kit Carson County, CO), 150 MW, Q4 2027 COD; and
- Arriba Wind (Lincoln County, CO), 200 MW, Q1 2029 COD.

Expansion of Renewable Energy Portfolio

Tri-State's first owned renewable energy resources, Axial Basin Solar (145 MW) and Dolores Canyon Solar (110 MW) came online in October 2025. With those additions, along with existing renewable PPA resources, the renewable resources on Tri-State's system total approximately 2 GW.[15] Tri-State's renewable generation capacity, actuals through 2024 and forecasted for 2025, is shown in Figure 4 below.

[15] 1,466 MW wind, solar, small hydro, and renewable Member generation; and 580 MW large hydro.

FIGURE 4 – TRI-STATE RENEWABLE GENERATION CAPACITY[16]



6. Update on Consideration of Acquisition of Cost-Effective New Clean Energy and Energy-Efficient Technologies

Commission Rule 3618(a)(VI)

Emerging Technologies

Tri-State expanded its generic resource data set for Phase I of the 2023 ERP to include additional clean energy and energy efficient technologies, as technologies continue to evolve and become more competitive.[17] Tri-State utilizes the Electric Power Research Institute ("EPRI") for advanced generation and storage research, input from internal Tri-State Generation Engineering staff, industry benchmarking, and relationships with vendors, stakeholders, and consultants to stay aware of the progress of emerging technologies at a utility scale that can assist in a clean

[16] Figure 4 does not include Western Area Power Administration Colorado River Storage Project or Loveland Area Projects hydro allocations.

[17] *See* Hearing Exhibit 101, Attachment LKT-16, Rev. 2, filed on May 15, 2024, in Proceeding No. 23A-0585E.

energy transition to maintain affordability and reliability for Tri-State's Utility Member Systems. Tri-State will continue to evaluate emerging technologies to consider for its 2027 ERP generic resource data set, to the extent the resources are utility-scale proven and cost-competitive.

Tri-State's entry of its resources into the SPP RTO in April 2026 is key for integrating intermittent resources on a large scale and further supporting affordable and reliable operations, while meeting carbon reduction targets.

Renewables

Tri-State's renewable resource portfolio includes utility scale projects and distribution level projects. Tri-State's wholesale power contract with each of its Utility Members and Board policies allow for, and facilitate, the development of local distributed resources in its Utility Members' service territories. The Federal Energy Regulatory Commission ("FERC") accepted, subject to refund and settlement procedures, Tri-State's amended Board Policy 115 effective August 6, 2025, enabling Utility Members to now self-supply up to 20% of their energy needs through distributed or renewable generation, a substantial increase from the previous 5% allocation. These renewable and distributed projects are helping to fulfill both Colorado and New Mexico Renewable Energy Standards ("RES")/Renewable Portfolio Standards ("RPS") requirements, as well as satisfy Utility Members'/consumers' interests in purchasing renewable power from locally-sited projects.

Figure 5 below shows the decline in capacity of these distributed projects through the end of 2024, reflecting the departures of United Power and Mountain Parks Electric, accounting for a decrease in distributed generation capacity of 49.6 MW. The number and capacity of these projects is expected to continue to grow, with a small net increase in 2025, as many of Tri-State's Utility Members remain interested in supporting local renewable projects.

FIGURE 5 – MEMBER RENEWABLE AND DISTRIBUTED GENERATION PROJECTS, NAMEPLATE CAPACITY UNDER CONTRACT, 2007-2024 AND FORECASTED for 2025

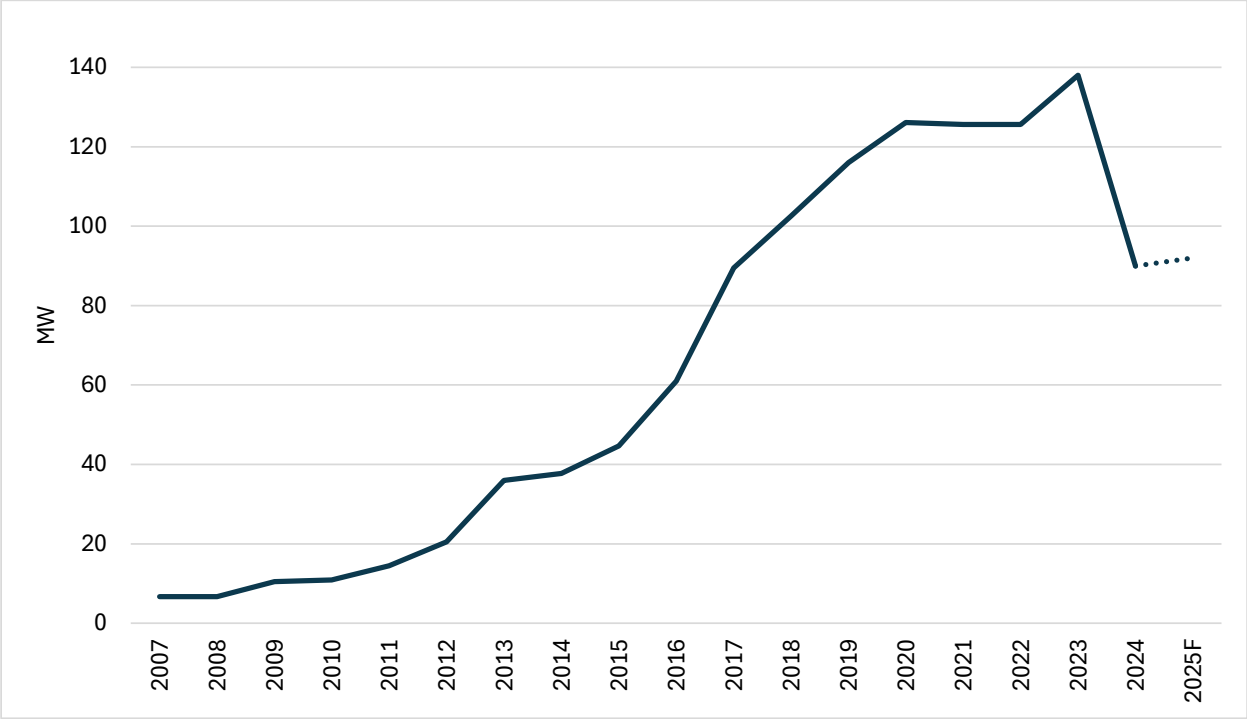
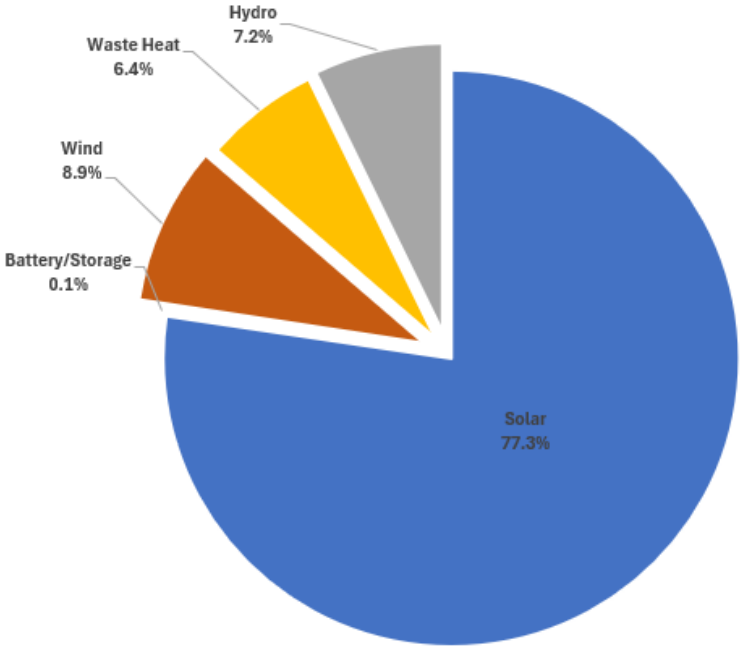


Figure 6 shows the breakdown of these projects by technology category. As of December 31, 2024, fifty-eight renewable or distribution generation projects totaling 90 MW were in operation across 20 Member Systems, with solar technology comprising over 77% of Member generation distributed resources.

FIGURE 6 – MEMBER BP 115 RENEWABLE AND DISTRIBUTED GENERATION PROJECTS BY TECHNOLOGY, NAMEPLATE CAPACITY OPERATING AS OF 12/31/2024



Bring Your Own Resource (BYOR)

Tri-State's BYOR program was accepted by FERC on August 2, 2025. Within this program Utility Members can bring forth resources equivalent up to 40% of their peak capacity needs through their owned or controlled projects, with Tri-State supporting all Utility Members by integrating BYOR projects into its multi-state system. BYOR allows Utility Members to have additional flexibility to develop resources under their Wholesale Electric Service Contracts with Tri-State, while not increasing wholesale rates or shifting costs between Utility Members. All load served under the BYOR resources remains Class A load.

Energy Efficiency

In 2024, Tri-State's long-standing energy efficiency program spent a total of $5.8 million on incentives in support of energy efficiency and certain electrification programs (not including administrative costs associated with this program). The programs delivered 56,133 MWh of first-year savings in Colorado, and an estimated 322,612 MWh of lifetime energy savings resulting from 2024 efficiency installations. Annual and cumulative savings from the program through 2024, including the removal of all items that have reached their established end of useful life, are shown in Figure 7 below.

FIGURE 7 – TRI-STATE 2024 ENERGY EFFICIENCY MEASURES AND SAVINGS, CUMULATIVE AND ANNUAL

Cummulative

Category	Typical Measures	kW Savings	kWh Savings
Agricultural	Irrigation Motors Variable Speed Drive Retrofits	13,065	22,226,468
C&I HVAC	Air Source and Ground Source Heat Pumps	3,471	2,716,881
C&I Lighting	LED Lighting Street & Parking Lot Lighting Refrigerated Case Doors	47,229	175,876,342
C&I Motors	Variable Speed Drive Retrofits and Process Measures	9,403	48,493,751
Residential HVAC	Air Conditioners Air Source and Ground Source Heat Pumps	50,255	42,700,554
Residential - Other	LED Lamps, Energy Star Appliances Electric Water Heaters Low Income Weatherization	54,728	30,597,885
Total		**178,151**	**322,611,881**

Annual Savings

Category	Typical Measures	kW Savings	kWh Savings
Agricultural	Irrigation Motors Variable Speed Drive Retrofits	738	1,175,175
C&I HVAC	Air Source and Ground Source Heat Pumps	139	447,190
C&I Lighting	LED Lighting Street & Parking Lot Lighting Refrigerated Case Doors	1,294	4,938,378
Industrial	Process Measures	3,076	36,674,828
Residential HVAC	Air Conditioners Air Source and Ground Source Heat Pumps	5,086	11,187,795
Residential - Other	LED Lamps, Energy Star Appliances Electric Water Heaters Low Income Weatherization	1,127	1,710,328
Total		**11,459**	**56,133,693**

On September 1, 2022, Tri-State submitted its 2023/24 Colorado Demand-Side Management ("DSM") Plan, informationally, in Proceeding No. 20A-0528E. The DSM Plan describes Tri-State energy efficiency programs and its plans to scale programs to meet energy savings targets agreed upon in the 2020 ERP Settlement Agreement ("Colorado EE Targets"), which began in 2023.

By the end of 2024, Tri-State met its second Colorado EE Target.

2024 Colorado EE Target		2024 Colorado EE Achievement	
0.50%	45.6 GWh	0.61%	56.6 GWh

The programs that contributed most significantly to the 2024 EE Target included: Air-Source Heat Pumps for Space Conditioning, Commercial Lighting, Oil and Gas, and Commercial and Industrial ("C&I") savings.

Tri-State anticipates meeting its 2025 Colorado EE Target due to growth in oil and gas ("O&G") sector energy efficiency projects. As of October 2025, Tri-State's EE program savings is 36.1 GWh or 60.1% of the 2025 Tri-State's goal of 60.04 GWh (0.75% of Colorado Member load). Tri-State held informational DSM Roundtable Meetings with interested stakeholders on June 17, 2025 and November 12, 2025.

Demand Response

Tri-State is committed to the development of in-house demand response ("DR") programs designed to meet the target of 4% of Colorado peak load under control in 2025 ("2025 Colorado DR Target").[18]

2025 Colorado DR Target	
4%	59.5 MW

Tri-State's Demand Response Rider was accepted by the Federal Energy Regulatory Commission ("FERC") effective May 2025.[19] Following FERC acceptance, Tri-State's DR programs became available to the entirety of the Tri-State Utility Membership in late May 2025, subject to Tri-State and relevant vendor implementation resources. These programs include:

- Irrigation Load Control
- Commercial & Industrial Load Control

[18] 2020 ERP Phase I Settlement Agreement, section 3.11.8. states: "Tri-State will either conduct an RFP for demand response prior to submitting its next ERP or develop in-house demand response offerings in Colorado by 2025 that are designed to control at least 4% of Tri-State's Colorado peak load."

[19] Docket No. ER25-1733.

- Smart Thermostats
- Member Battery Energy Storage

Between 2026 and 2029, Tri-State will continue to evaluate additional program concepts to support reaching the 2030 Colorado DR Target,[20] including but not limited to water heater controls, electric vehicle charging, and distribution-scale virtual power plants.

In 2025, Tri-State worked with its contracted partner, OATI, to implement a new Distributed Energy Resource Management System ("DERMS") which is a platform that enables event scheduling, DR and Distributed Energy Resource ("DER") integration and dispatch, DR/DER meter data analysis, and reporting. Most facets of the OATI DERMS are now operational for Tri-State users, with development resources now focused on Member system integrations. Tenants of the OATI DERMS platform will be made available to participating Utility Members, subject to terms and conditions of the Demand Response programs. Additionally, Tri-State has partnered with an outside consultant to assist with program design recommendations, in collaboration with Utility Members.

As of November 2025, the total DR capacity enrolled is 40 MW; in addition, approximately 45 battery assets are slated for enrollment once associated funding is released and will join the DR program at that time. Through the remainder of the year, Tri-State is working with Utility Members to continue to implement DERMS tenants and enroll additional C&I, residential and irrigation load, as well as battery storage resources. Tri-State informed stakeholders of its delay in implementing the DR program, and provided an update on the new DR Rider, during the June 17, 2025 DSM Roundtable Meeting.

7. Update on Emissions Reductions

In January 2022, Tri-State filed a Settlement Agreement with numerous parties to its 2020 Phase I ERP. Emissions reductions were among the many topics addressed through the Settlement Agreement. Tri-State agreed to emissions reduction targets for Tri-State's wholesale sales of electricity in Colorado, with respect to Tri-State's APCD-verified 2005 Baseline, as follows:

[20] 2023 ERP Phase I Settlement Agreement, section 4.9.1 states: "Tri-State will aim to control at least 5.5% of Tri State's Colorado peak load through demand response programs by 2030."

TABLE 3 – GHG EMISSIONS REDUCTION TARGETS[21]

Year	Percentage GHG Emissions Reduction
2025	26%
2026	36%
2027	46%
2030	80%

Tri-State also committed to including the following information in its APRs in each year following a year shown in Table 3:[22]

- The amount of GHG emissions, in tons, related to Tri-State's wholesale sales of electricity in Colorado for the prior calendar year, as reported by Tri-State to the Colorado Air Quality Control Commission under Regulation 22; and
- The percentage reduction in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado for the prior calendar year, computed using the CEP Guidance and the 2005 Baseline. The percentage reduction will be consistent with the tonnages that Tri-State reports under Regulation 22.
- Information on how the emission rate for unspecified energy purchases specified by the CEP Guidance differed from the actual annual reported emissions rate for those purchases. Tri-State also will provide information as to whether any adjustments in operations or resource acquisitions are needed in order to ensure Tri-State meets the targets.

Tri-State will begin reporting this information in its December 2026 APR, for the 2025 GHG emissions reduction target.

As of October 31, 2025, Tri-State is forecasting a ~31% reduction in greenhouse gas (GHG) emissions from energy serving its Colorado load, from a 2005 baseline; the 2025 target is a 26% reduction,[23] making Tri-State on-target toward achieving its first Colorado emissions reduction milestone.

[21] Section 3.3.4. of the Settlement Agreement filed in Proceeding No. 20A-0528E.
[22] Section 3.3.11. of the Settlement Agreement filed in Proceeding No. 20A-0528E.
[23] Section 3.3.4. of the Settlement Agreement filed in Proceeding No. 20A-0528E.