NEVADA REGIONAL HAZE REVISION TO THE STATE IMPLEMENTATION PLAN FOR THE SECOND PLANNING PERIOD

Revision to the Plan for Implementing
Section 308 (40 CFR § 51.308)
of the Regional Haze Rule
Second Implementation Period (2018-2028)

Public Comment Draft

NEVADA DIVISION OF
ENVIRONMENTAL
PROTECTION

State of Nevada
Division of Environmental Protection
901 South Stewart Street, Suite 4001
Carson City, Nevada 89701

February 28, 2025

EXECUTIVE SUMMARY

Introduction

The Regional Haze Rule (RHR) requires Nevada to address statewide emissions of visibility impairing pollutants that contribute to regional haze in each mandatory Class I Area (CIA) located in Nevada and nearby states. Jarbidge Wilderness Area (WA) is the only mandatory CIA located in Nevada. Under the RHR, Nevada is required to submit a State Implementation Plan (SIP) addressing how progress towards natural visibility conditions in the CIAs will be achieved. The State of Nevada submitted its Regional Haze SIP for the Second Planning Period to the United States Environmental Protection Agency (USEPA) Region 9 on August 12, 2022, to satisfy the rule requirements outlined in 40 Code of Federal Regulations (CFR) Part 51, Subpart P, Section 51.308. The USEPA found that Nevada's SIP revision for the Second Planning Period met the completeness criteria outlined in 40 CFR Part 51, Appendix V, and is currently reviewing its approvability. This submittal is a revision to Nevada's Regional Haze SIP for the Second Planning Period.

Reconsideration of Nevada's 2022 Regional Haze SIP

On July 13, 2023, NV Energy notified Nevada's Division of Environmental Protection (NDEP) of plans to file an Integrated Resource Plan (IRP) amendment with the Public Utilities Commission of Nevada (PUCN). This amendment sought approval for modifications and emissions controls at the Tracy and Valmy generating stations. Since the Tracy and Valmy generating stations were part of Nevada's Regional Haze SIP, NDEP submitted a letter on July 27, 2023, informing the USEPA of its partial withdrawal of the Nevada State Implementation Plan for the Regional Haze Rule for the Second Planning Period. Having completed the four-factor re-analysis and establishing new reasonable progress requirements, NDEP is now resubmitting the withdrawn elements as a revision to Nevada's Regional Haze State Implementation Plan.

Changes in the energy landscape along with transmission system reliability considerations in Nevada necessitated reconsideration of the intent to retire North Valmy Units 1 and 2 by December 31, 2028, and Tracy Unit 4 Piñon Pine by December 31, 2031. In August 2023, NV Energy filed an application for the Fifth Amendment to the 2021 Joint IRP with the PUCN. In part, the Fifth Amendment sought approval to convert the existing coal fueled plant at North Valmy Generating Station to a cleaner natural gas-fueled plant, and to continue operation of the North Valmy Station and Tracy Unit 4 Piñon Pine to 2049. In March 2024, the PUCN approved proceeding with these projects at North Valmy and Tracy Stations.

North Valmy and Tracy Unit 4 Piñon Pine

NV Energy completed new four-factor analysis for both the North Valmy Units and Tracy Unit 4 Piñon Pine. The updated analyses utilize an emissions baseline derived from the annual average of emissions reported in 2016 through 2018. Conversion of both Valmy Units to natural gas firing and the installation of selective non-catalytic reduction (SNCR) or flue gas recirculation (FGR) is estimated to result in emissions reductions, compared to the baseline, of 1,144 tons per year (tpy) of oxides of nitrogen (NO_x), 2,309 tpy of sulfur dioxide (SO_2), and 16.4 tpy of coarse particulate matter (PM_{10}), amounting to a total of 3,469 tpy reductions of visibility impairing pollutants. While the installation of selective catalytic reduction (SCR) at Tracy Unit 4 Piñon Pine is expected to reduce NO_x emissions by 225 tpy. Nevada's SIP revision is also relying on existing controls at these units, that effectively control visibility impairing pollutants. The use of the new and existing controls has been included in Nevada's Long-Term Strategy for the second implementation period through the adoption of amendments to Nevada Administrative Code 445B.

Lhoist Apex Plant

The Lhoist Apex Plant is a lime production facility located in Clark County, NV and operates four horizontal rotary preheater lime kilns. NDEP determined the implementation of Low- NO_x Burners (LNB) at Kiln 1, and implementation of SNCR at Kilns 1, 3, and 4 as necessary to achieve reasonable progress during the second implementation period of Nevada's Regional Haze SIP. The requirements to achieve reasonable progress were established in the Apex Plant's Authority to Construct (ATC) Permit issued and enforced by the Clark County Department of Environment and Sustainability and incorporated by reference into Nevada's Regional Haze SIP. Apex's ATC Permit expired 18 months after its original issue date of August 3, 2022, and was reissued by the Clark County Department of Environment and Sustainability on February 6, 2024. This permit will be issued once more before submission of this revision. All referenced permit conditions remain the same as those in Nevada's SIP submitted on August 12, 2022. These conditions are incorporated by reference into Nevada's Regional Haze SIP Long-Term Strategy for the second implementation period as a source-specific SIP revision for approval.

Graymont Pilot Peak Plant

The Graymont Pilot Peak Plant is a lime production facility located in Elko County, NV and operates three horizontal rotary preheater lime kilns. NDEP determined that the continued use of LNBs at all three kilns is necessary to make reasonable progress. A compliance deadline of 240 days from issuance of the updated permit was set to allow for continuous emissions monitoring system (CEMS) requirements. This compliance date has been met by Pilot Peak. A minor revision of the Pilot Peak Class I Air Quality Operating Permit (AP3274-1329.03) was issued by the State of Nevada June 14, 2024. All referenced permit conditions remain the same as those in Nevada's SIP submitted on August 12, 2022. These conditions are incorporated by reference into Nevada's Regional Haze SIP Long-Term Strategy for the second implementation period as a source-specific SIP revision for approval.

Long-Term Strategy

Significant emission reductions are expected to achieve reasonable progress for the second implementation period of Nevada's Regional Haze SIP. Nevada expects a total reduction in primary visibility impairing pollutants (SO_2, NO_x, and PM_{10}) of 4,187 tpy as a result of controls implemented during the second round. Baseline 2028 visibility conditions at Jarbidge WA are projected at 7.764 dv during the most impaired days and 1.724 dv during the clearest days. An updated reasonable progress goal (RPG) for the end of the Second Planning Period at Jarbidge WA was calculated at 7.758 dv during the most impaired days and 1.720 dv during the clearest days. These revised estimates show a 0.001 dv decline in visibility during the most impaired days and no change in visibility during the clearest days when compared to Nevada's 2022 Regional Haze SIP as can be seen in Table ES-1.

Table ES-1: 2028 Visibility vs. Proposed RPGs for Jarbidge WA

	2028OTBa2 (dv)	RPG (dv)	Revised RPG (dv)	Rounded (dv)
Most Impaired Days	7.764	7.757	7.758	7.76
Clearest Days	1.724	1.720	1.720	1.72

The URP glidepath, along with 2028 RPGs, at Jarbidge WA during the second implementation period is provided in Figure ES-1. This figure shows that visibility during the most impaired days is expected to improve in 2028 (7.76 deciviews) compared to the 2000-2004 baseline conditions (8.73 deciviews). It also shows that the visibility conditions for the clearest days in 2028 (1.72 deciviews) are expected to be better than the observed values for 20 percent clearest days from the 2000-2004 baseline condition (2.56 deciviews). The glidepath assumes natural visibility conditions of 7.39 deciviews, including adjustments to account for international emissions and prescribed fire impacts. In order to achieve natural conditions by 2064, visibility projections during the most impaired days must be 8.20 deciviews or below by 2028. NDEP's 2028 RPG for the most impaired days of 7.76 deciviews confirms that visibility at Jarbidge WA is on track to achieve natural conditions by 2064.

Figure ES-1: Jarbidge WA Final URP Glidepath with 2028 Reasonable Progress Goals

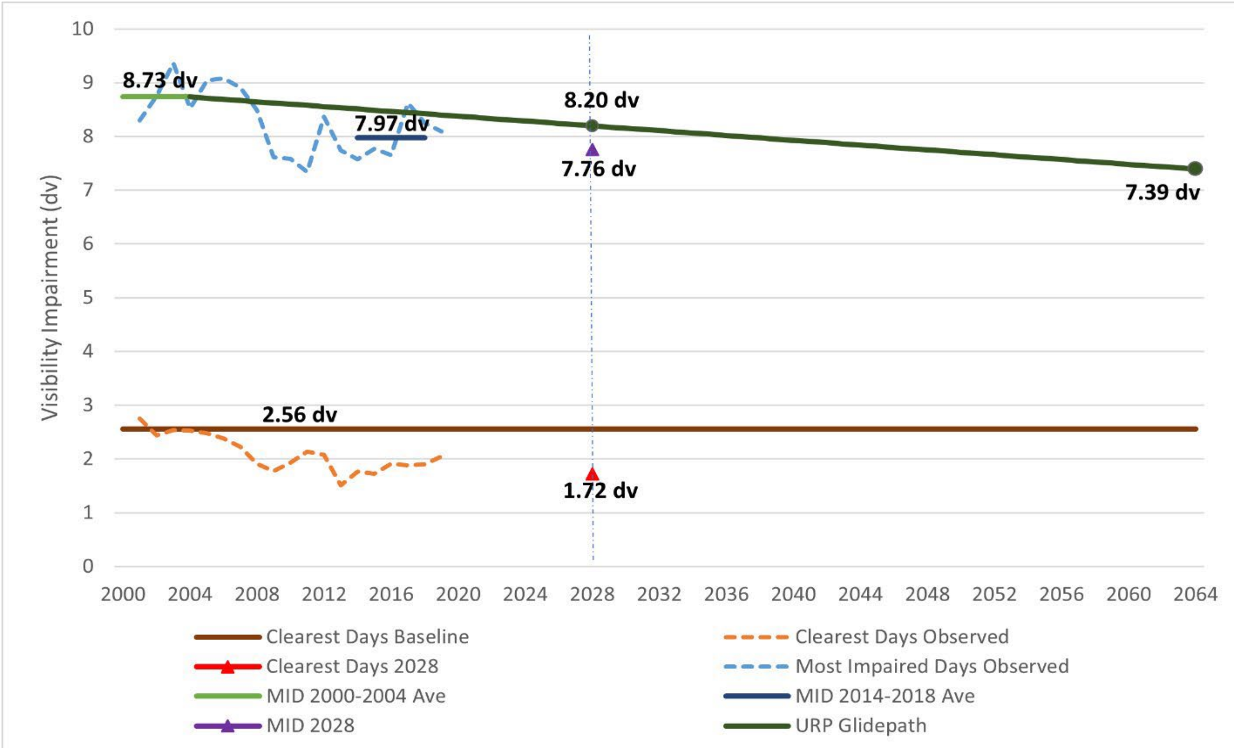


TABLE OF CONTENTS

Acronyms, Abbreviations and Terms

2014v2	2014 Emissions Inventory Version 2
2028OTBa2	2028 On-the-Books/On-the-Way Emission Inventory Version 2
2028PAC2	2028 Potential Additional Controls Emission Inventory Version 2
ARP	Acid Rain Program
BART	Best Available Retrofit Technology
BACT	Best Available Control Technology
BLM	Bureau of Land Management
CAA	Clean Air Act
CAMx	Comprehensive Air Quality Model with Extensions
CARB	California Air Resources Board
CASTNET	Clean Air Status and Trends monitoring network
CCDES	Clark County Department of Environment and Sustainability
CD	Consent Decree
CIA	Class I Area
CENWRAP	Central West Regional Air Partnership
CFR	Code of Federal Regulations
CM	Coarse Matter
CSN	Chemical Speciation Network
CTI	Cleaner Trucks Initiative
DERA	Diesel Emissions Reduction Act
DLN	Dry Low NO_x
EGU	Electrical Generating Unit
EIMP	Emission Inventories and Modeling Protocol Work Group
EJ	Environmental Justice
EWRT	Extinction-Weighted Residence Time
FGD	Flue Gas Desulfurization
FGR	Flue Gas Recirculation
FIP	Federal Implementation Plan
FLM	Federal Land Manager
FSWG	Fire and Smoke Work Group
FWS	Fish & Wildlife Service
GEOS-Chem	Goddard Earth Observing System global chemical model
GHG	Greenhouse Gas
HI	Haze Index
HMS	Hazard Mapping System
IMPROVE	Interagency Monitoring of Protected Visual Environments
IWDW	Intermountain West Data Warehouse
JARB1	Jarbidge Wilderness Area IMPROVE Monitor
LNB	Low-NO_x Burner(s)
LEV	Low-Emission Vehicle
LTS	Long-Term Strategy
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standards
Mm^{-1}	Inverse Megameter

MOU	Memorandum of Understanding
MOVES	Motor Vehicle Emission Simulator
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NAC	Nevada Administrative Code
NDEP	Nevada Division of Environmental Protection
NEI	National Emission Inventory
NEIv2	National Emission Inventory version 2
NG	Natural Gas
NPS	National Park Service
NRS	Nevada Revised Statutes
NSR	New Source Review
NTEC	National Tribal Environmental Council
OFA	Over-Fired Air
OGWG	Oil & Gas Work Group
PNG	Pipeline Natural Gas
PSAT	Particulate Source Apportionment Technology
PSD	Prevention of Significant Deterioration
PUC	Public Utilities Commission
RAVI	Reasonable Attributable Visibility Impairment
RepBase2	Representative Baseline Emission Inventory Version 2
RH	Regional Haze
RHPWG	Regional Haze Planning Work Group
RHR	Regional Haze Rule
RMC	Regional Modeling Center
RPG	Reasonable Progress Goal(s)
RPO	Regional Planning Organizations
RPS	Renewable Portfolio Standard
RRF	Relative Response Factor
SCR	Selective Catalytic Reduction
SEC	State Environmental Commission
SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kerner Emissions
SNCR	Selective Non-Catalytic Reduction
TSS	Technical Support System
USEPA	United States Environmental Protection Agency
USFS	United States Forest Service
URP	Uniform Rate of Progress
VIEWS	Visibility Information Exchange Web System
WA	Wilderness Area
WAQS	Western Air Quality Study
WEP	Weighted Emissions Potential
WESTAR	Western States Air Resources Council
WGA	Western Governors Association
WPS	WRF Preprocessing System
WRAP	Western Regional Air Partnership
WRF	Weather Research and Forecasting
ZEV	Zero-Emission Vehicle

Chemicals and Chemical Compounds

CO	Carbon Monoxide
EC	Elemental Carbon
HNO_3	Nitric Acid
NH_3	Ammonia
NH_4	Ammonium
NH_4NO_3	Ammonium Nitrate
$(NH_4)_2SO_4$	Ammonium Sulfate
NMHC	Non-Methane Hydrocarbons
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_3	Nitrate
NO_x	Oxides of Nitrogen
OC	Organic Carbon
OMC	Organic Matter Carbon
PM	Particulate Matter
$PM_{2.5}$	Fine Particulate Matter (2.5 micrometers and smaller in diameter)
PM_{10}	Coarse Particulate Matter (10 micrometers and smaller in diameter)
POA	Primary Organic Aerosols
SO_2	Sulfur Dioxide
SO_4	Sulfate
VOC	Volatile Organic Compounds

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION

On August 12, 2022, NDEP submitted the Nevada SIP for the Second Planning Period to the USEPA. The USEPA found that Nevada's SIP revision for the Second Planning Period meets the completeness criteria outlined in 40 CFR Part 51, Appendix V, and is currently reviewing its approvability. However, on July 13, 2023, NV Energy notified NDEP of plans to file an IRP amendment with the PUCN seeking approval to pursue modifications and appropriate emissions controls at the Tracy and Valmy generating stations. Since the Tracy and Valmy generating stations were part of Nevada's Regional Haze SIP, NDEP submitted a letter on July 27, 2023, informing the USEPA of its partial withdrawal of the Nevada State Implementation Plan for the Regional Haze Rule for the Second Planning Period, as it pertains to the Tracy and Valmy generating stations. Having completed the four-factor re-analysis and establishing new reasonable progress requirements, NDEP is now resubmitting the withdrawn elements as a revision to Nevada's Regional Haze State Implementation Plan.

1.1 Background

1.1.1 Regional Haze Requirements

The RHR requires Nevada to address statewide emissions of visibility impairing pollutants that contribute to Regional Haze in each mandatory CIA located in Nevada and nearby states. Jarbidge Wilderness Area (WA) is the only mandatory CIA located in Nevada. Under the RHR, Nevada is required to submit a SIP addressing how progress towards natural visibility conditions in the CIAs will be achieved. The State of Nevada submitted its Regional Haze SIP for the Second Planning Period to the USEPA Region 9 in August 2022, to satisfy the rule requirements outlined in 40 CFR Part 51, Subpart P, Section 51.308. This submittal is a revision to Nevada's Regional Haze SIP for the Second Planning Period.

1.1.2 Second SIP Submittal

The RHR has requirements that are implemented over a multidecadal period, which is broken into several planning phases to ultimately meet the national goal of returning visibility at all designated CIAs to natural conditions. The approach taken in preparing this Regional Haze SIP revision is to address the second planning period (2018 through 2028). This revision replaces the portions of the Regional Haze SIP for the Second Planning Period withdrawn by NDEP on July 23, 2023, to ensure the SIP meets the requirements of improving visibility for the most impaired days and ensuring no degradation in visibility for the clearest days for the period ending in 2028, the second planning period in the federal rule. Nevada's RH SIP revision has been prepared by the NDEP and contains strategies and elements related to each requirement of the federal rule.

1.1.3 Valmy Previous Control Determinations

NV Energy had committed to cease operations and shutdown both coal-fired electrical generating units at North Valmy Generating Station by December 31, 2028. With this closure date, no additional controls on either unit were cost-effective or necessary to achieve reasonable progress. NDEP was relying on existing control measures at the North Valmy Generating Station to make reasonable progress. These measures included baghouse and air atomized ignitors to control PM_{10} at both Units, LNB and Over-Fired Air (OFA) to control NO_x for both Units, and a spray dryer with lime slurry to control SO_2 at Unit 2. NV Energy's four-factor analysis relied on an emissions baseline derived from the annual average of emissions reported in 2016 through 2018. By the end of 2028, or the end of the second implementation period, 1,746 tons per year (tpy) of NO_x reductions, 2,313 tpy SO_2 reductions, and 60 tpy of PM_{10} reductions were expected from the closure of both Valmy units, amounting to a total of 4,119 tpy reductions of visibility impairing pollutants. Western Regional Air Partnership WRAP emissions inventories underestimated the final reductions expected to be achieved at North Valmy Generating Station. Emissions reported by the Valmy Generating Station in 2016 were used to forecast Valmy's emissions in the 2028OTBa2 modeling emission inventory, or 2028 baseline before the implementation of potential controls. Beyond the 2028OTBa2 model, the closure of Valmy would have reduced NO_x emissions by an additional 1,583 tpy and SO_2 emissions by an additional 2,281 tpy by the end of the second implementation period.

1.1.4 Tracy Previous Control Determinations

The Tracy Generating Station's Unit 4 Piñon Pine is a GE 6FA combined cycle combustion turbine + duct burner, identified by NDEP as Unit7/System 07C (Appendix A.2), by the EPA as Unit 6, by the NV Energy Four-Factor analysis as Tracy Unit 6 - Piñon Pine #4 (Appendix B) and will be referred to in this document as Tracy Unit 4 Piñon Pine. Upon conclusion of the initial four-factor analysis and after discussions with NDEP, NV Energy committed to NDEP to cease operations at Tracy Unit 4 Piñon Pine by December 31, 2031. This new closure date reduced the remaining useful life of the unit and any potential additional controls down to 6 years, resulting in a NO_x emissions control costs of $10,064/ton for Selective Catalytic Reduction (SCR) and $17,355/ton for Dry Low NO_x (DLN) Combustors. NDEP does not consider controls above $10,000/ton as cost-effective for the second implementation period of the Regional Haze Rule. Reductions from the closure of this unit were not expected to be observed during the second implementation period, ending in 2028, but would be observed in Nevada's third implementation period of the Regional Haze Rule. Because of this, expected reductions were not quantified or assumed in Nevada's reasonable progress goals for the second implementation period.

In the 2028OTBa2 emission inventory, facility emissions for Tracy are taken from annual emissions reported in 2018. By the end of the second implementation period in 2028, final reductions achieved from the unit's closure will not be observed yet. To reflect this, NDEP expected no emission reductions at the Tracy Generating Station as a result of the initial round's four factor analyses by the end of the planning period.

Although there is a slight difference in NO_x emissions between 2028OTBa2 and the Emissions After Controls inventories, as shown in Table 5-18 of the Nevada Regional Haze SIP submitted August 2022, this is a result of different baseline emissions used and not because of reductions achieved from add-on controls considered in the four-factor analysis. Because of this, there were no adjustments made to the reasonable progress goals provided by the WRAP to reflect additional reductions at Tracy.

Aside from the closure of the Tracy Unit 4 Piñon Pine December 31, 2031, Nevada's SIP revision is also relying on existing controls, listed in Table 5-19 of the Nevada Regional Haze SIP submitted August 2022, that effectively control visibility impairing pollutants. The continued use of these existing controls will be included in Nevada's Long-Term Strategy for the second implementation period, along with the current corresponding NO_x emission limits for each unit listed in the facility's current operating permit. These listed controls target NO_x emissions only since the Tracy facility primarily burns pipeline natural gas with negligible SO_2 and PM_{10} emissions.

1.2 NV Energy Testimony as to Why Closure is Not Feasible

On July 13, 2023, NV Energy notified NDEP of plans to file an IRP amendment with the PUCN. This amendment sought approval for modifications and emissions controls at the Tracy and Valmy generating stations. If approved, any plans to modify the Units' operations and corresponding Title V permits will warrant a four-factor re-analysis in establishing new reasonable progress requirements for the Plan as it pertains to the Units.

Changes in the energy landscape along with transmission system reliability considerations in Nevada necessitated reconsideration of the intent to retire North Valmy Units 1 and 2 by December 31, 2028, and Tracy Unit 4 Piñon Pine by December 31, 2031. In August 2023, NV Energy filed an application for the Fifth Amendment to the 2021 Joint IRP with the PUCN. In part, the Fifth Amendment sought approval to convert the existing coal fueled plant at North Valmy Generating Station to a cleaner natural gas-fueled plant, and to continue operation of the North Valmy Station and Tracy Unit 4 Piñon Pine to 2049. Based on this filing, the state of Nevada withdrew portions of the State Implementation plan for regional haze to re-evaluate emission control measures that may be necessary to achieve reasonable progress during the second implementation period of the RHR in Nevada. In March 2024, the PUCN approved proceeding with these projects at North Valmy and Tracy Stations.

1.3 Partial Withdrawal

On July 27, 2023, NDEP submitted a letter informing the USEPA of its partial withdrawal of the Nevada State SIP for the RHR for the Second Planning Period. NDEP requested that the four-factor control determinations, also referred to as reasonable progress determinations, for Tracy

Unit 4 Piñon Pine and North Valmy Generating Station's Unit 1 and Unit 2 (collectively referred to as Units) of the Plan be withdrawn from inclusion in the Nevada SIP.

Plan locations with language or data pertaining to the final reasonable progress determinations for the Units (i.e., closure requirements, permit conditions incorporated by reference, and control determinations) that NDEP requested be withdrawn included, but were not limited to:

- Executive Summary
- Section 5.5 through 5.6
- Subsection 5.4.7
- Section 7.7
- Table 5-5 through 5-19
- Table 5-40
- Table 7-1
- Figure 5-1
- Appendices A.5 and A.6
- Appendices B.5.a and B.6.a

After the completion of the four-factor re-analysis and establishing new reasonable progress requirements, NDEP is now resubmitting the withdrawn elements as a revision to the Plan. Sections 2 and 3 of this document replaces the portions of Sections 5.5 through 5.6 of the Regional Haze SIP submitted August 12, 2022, pertaining to Valmy Units 1 and 2 and Tracy Unit 4 Piñon Pine. Section 4 of this document serves as NDEP's submittal of permits reissued since the Regional Haze SIP submitted August 12, 2022. Section 4.1 details the Authority to Construct Permit for the Lhoist Apex plant, while section 4.2 details a minor revision affecting Graymont Pilot Peak. Section 5 replaces the portions of sections 5.4.7 (Cumulative Emissions Reductions), 6.8 through 6.9, 7.2 and 7.7 of the Regional Haze SIP submitted August 12, 2022, pertaining to Valmy Units 1 and 2 and Tracy Unit 4 Piñon Pine.

1.4 Nevada Four-Factor Approach

As a result of the partial withdrawal and revised four-factor analyses for the North Valmy and Tracy generating stations NDEP has determined the following control measures, listed in Table 1-1, as necessary to make reasonable progress during the second implementation period. Table 1-1 replaces Table 5-5 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023. Further discussion of the resubmitted elements affecting the North Valmy and Tracy facilities, units, controls, and characterizations of the four statutory factors is provided in the following sections.

Table 1-1: Control Measure Necessary to Make Reasonable Progress

Facility	Unit	Control	Controlled Pollutant	Existing/ New	Compliance Deadline
North Valmy Generating Station	Unit 1	Use of Pipeline Quality Natural Gas	PM_{10}	New	June 1, 2027
		Use of Pipeline Quality Natural Gas	SO_2	New	June 1, 2027
		LNB and SNCR, FGR, or SCR	NO_x	New	No Later than 36 months after SIP approval
	Unit 2	Use of Pipeline Quality Natural Gas	PM_{10}	New	June 1, 2027
		Use of Pipeline Quality Natural Gas	SO_2	New	June 1, 2027
		LNB and SNCR, FGR, or SCR	NO_x	New	No Later than 36 months after SIP approval
Tracy Generating Station	Unit 5	Dry Low NO_x Combustor	NO_x	Existing	Upon SIP approval
	Unit 6	Dry Low NO_x Combustor	NO_x	Existing	Upon SIP approval
	Tracy Unit 4 Piñon Pine	Steam Injection	NO_x	Existing	Upon SIP approval
		SCR	NO_x	New	No Later than 36 months after SIP approval
	Unit 32	Dry Low NO_x Combustor and SCR	NO_x	Existing	Upon SIP approval
	Unit 33	Dry Low NO_x Combustor and SCR	NO_x	Existing	Upon SIP approval
Apex Plant	Kiln 1	LNB	NO_x	New	No later than two years after SIP approval
		SNCR	NO_x	New	
	Kiln 3	LNB	NO_x	Existing	
		SNCR	NO_x	New	
	Kiln 4	LNB	NO_x	Existing	
		SNCR	NO_x	New	
Pilot Peak Plant	Kiln 1	LNB	NO_x	Existing	240 days
	Kiln 2	LNB	NO_x	Existing	240 days
	Kiln 3	LNB	NO_x	Existing	240 days

2. RECONSIDERATION OF NORTH VALMY GENERATING STATION UNITS 1 & 2

2.1 Unit Description

The North Valmy Generating Station is an electric generating facility located at 23755 Treaty Hill Road in Valmy, NV, approximately 162 kilometers (km) southwest of the Jarbidge Wilderness Class I area in Elko County, NV. The electric generating units at the facility consist of two coal-fired boilers that provide high pressure steam to steam turbine generators used to produce electricity. This generating station is co-owned by NV Energy and Idaho Power with Idaho Power exiting coal operations at Unit 1 in 2019. Idaho Power has committed to participating in the conversion of both units to natural gas and remaining a co-owner.

Unit 1 at the North Valmy Station is a Babcock & Wilcox balanced draft, dry bottom, opposed wall-fired geometry boiler with a maximum allowable heat input rate of 2,560 MMBtu/hr. The nominal net electric generating capacity of Unit 1 is 237 MW. The unit went into commercial operation in 1981. The Unit 1 coal-fired boiler is equipped with a fabric filter baghouse to control particulate matter (PM) emissions and multi-stage combustion to control NO_x emissions through the use of LNBs and OFA.

Unit 2 at the North Valmy Station is a Foster Wheeler balanced draft, dry bottom single wall-fired geometry boiler with a maximum heat input rate of 2,881.0 MMBtu/hr. The nominal net electric generating capacity of Unit 2 is 264 MW. The unit entered commercial operation in 1985. This unit is equipped with a fabric filter baghouse to control PM emissions, multi-stage combustion (LNBs and OFA) to control NO_x emissions, and a lime slurry-based spray dryer to control SO_2 emissions.

2.2 Updated Four-Factor Analysis Summary

NV Energy submitted a revised four-factor analysis to include the removal of closure and the added conversion of North Valmy to natural gas firing. Table 2-1 outlines the files referenced for North Valmy Generating Station. Documents used in the original reasonable progress determination can be found in the Regional Haze SIP submitted on August 12, 2022. Table 2-1 replaces Table 5-6 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023. For the purposes of the new control determinations made as part of this SIP revision, NDEP is relying on the updated four-factor analysis for North Valmy and Tracy provided in Appendix B of this SIP revision.

Table 2-1: Location of Four-Factor Analysis Documents for Valmy

Full Document Title	Shortened Document Title	Date	Document Location
Regional Haze Reasonable Further Progress Four Factor Analysis	*NVE Analysis*	March 13, 2020	SIP submitted on 8/12/2022
RE: Response to Request for Additional Information	*Response Letter 1*	July 8, 2020	SIP submitted on 8/12/2022
RE: Response to a Second Follow-up Request for Additional Information	*Response Letter 2*	January 15, 2021	SIP submitted on 8/12/2022
RE: Response to a Third Follow-up Request for Additional Information	*Response Letter 3*	April 16, 2021	SIP submitted on 8/12/2022
RE: Response to a Fourth Follow-up Request for Additional Information	*Response Letter 4*	May 7, 2021	SIP submitted on 8/12/2022
RE: Response to a Fifth Follow-up Request for Additional Information (Valmy specific)	*Response Letter 5.1*	August 27, 2021	SIP submitted on 8/12/2022
RE: Response to a Fifth Follow-up Request for Additional Information (Tracy specific)	*Response Letter 5.2*	October 11, 2021	SIP submitted on 8/12/2022
RE: Response to a Sixth Follow-up Request for Additional Information	*Response Letter 6*	April 29, 2022	SIP submitted on 8/12/2022
RE: Response to a Seventh Follow- up Request for Additional Information	*Response Letter 7*	May 27, 2022	SIP submitted on 8/12/2022
RE: NV Energy Response to an Eighth Follow-Up Request for Additional Information	*Response Letter 8*	August 5, 2022	SIP submitted on 8/12/2022
Regional Haze Reasonable Further Progress: Updated Four Factor Analysis NV Energy North Valmy and Tracy Generating Stations	*NV Energy's four-factor analysis*	March 2024	Appendix B
Nevada Regulation	*Regulation*	September 17, 2024	Appendix C
RE: Response to Request for Additional Information Regional Haze Reasonable Further Progress: Updated Four Factor Analysis NV Energy North Valmy and Tracy Generating Stations	*Response Letter 9*	July 24, 2024	Appendix F

2.2.1 Baseline Emissions

For NV Energy's four-factor analysis for the North Valmy Generating Station, baseline emissions were derived from the annual average of emissions observed from 2016 through 2018. Table 2-2 summarizes what the projected average emission rates from North Valmy Units 1 and 2 would have been during the baseline period had the units been converted to natural gas firing at that time. These estimates utilize the average electric generating rate for each unit, each unit's projected net heat rate following conversion to natural gas firing, and USEPA emission factors from the latest revision of AP-42: Compilation of Air Emission Factors, Section 1.4 for natural gas-fired boilers. For the NO_x emission estimates, the projected emission rates following conversion to natural gas firing assume that Units 1 and 2 would be equipped with new Low NO_x natural gas-fired burners with an emission rate of 0.137 lb/MMBtu. New LNBs are included because the current burners employed on the units to burn coal are not designed to be fired with natural gas and LNBs are considered the replacement standard. NDEP is relying on NV Energy's four-factor analysis (Appendix B) and *Response Letter 9* (Appendix F) for the derivation of the 0.137 lb/MMBtu emission rate.

The estimated emission rates presented in Table 2-2 illustrate that converting North Valmy Units 1 and 2 to natural gas firing will result in significant reductions in all visibility-impairing pollutants: over 99% reduction in SO_2 emissions, 56% reduction in NO_x emissions, and 27% reduction in PM_{10} emissions compared to the 2016-2018 baseline values. Table 2-2 replaces Table 5-7 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023.

Table 2-2: Valmy Four-Factor Analysis Baseline Emissions

	SO_2	**NO_x**	**PM_{10}**
Baseline Emission Rates for Unit 1			
Estimated Emissions	**1.48 ton/yr** **0.0006 lb/MMBtu**	**344.6 ton/yr** **0.1373 lb/MMBtu**	**18.71 ton/yr** **0.0075 lb/MMBtu**
Baseline Emission Rates for Unit 2			
Estimated Emissions	**1.96 ton/yr** **0.0006 lb/MMBtu**	**457.8 ton/yr** **0.1373 lb/MMBtu**	**24.85 ton/yr** **0.0075 lb/MMBtu**

2.2.2 Identification of Technically Feasible Controls

For the North Valmy Generating Station Units 1 and 2, NV Energy identified selective catalytic reduction (SCR), flue gas recirculation (FGR), and selective non-catalytic reduction (SNCR) as technically feasible control measures in controlling NO_x emissions. The conversion to natural gas firing will sufficiently reduce SO_2 emissions such that there are no technically feasible add-on control options for SO_2 or PM_{10} emissions.

2.3 Cost of Compliance

A summary of the cost-effectiveness values for each technically feasible control technology considered at North Valmy Generating Station is provided in Table 2-3. Table 2-3 replaces Table

5-8 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023.

2.3.1 Selective Non-Catalytic Reduction

The capital and annualized operating costs for SNCR for Units 1 and 2 were estimated using the SNCR Cost Calculation Spreadsheet in USEPA's Control Cost Manual 2. A retrofit factor of 1.0 was used based on the assumption that retrofit of SNCR on both units would likely be relatively straightforward. A rate of 6.95% was used to annualize the capital cost of each alternative. This is NV Energy's current firm-specific overall cost of capital approved by the PUCN in the most recent general rate case. A discussion of NV Energy's cost of capital can be found in Appendix C of NV Energy's four-factor analysis (Appendix B of this document) and *Response Letter 9* (Appendix F).

Utilizing the Control Cost Manual spreadsheet in evaluating SNCR as a potential control measure at both Valmy units, a cost-effectiveness value of $9,740/ton and $8,018/ton is estimated for Unit 1 and 2, respectively. The total annual cost of implementing SNCR on Unit 1 is estimated at $840,000 and is projected to reduce NO_x emissions by 86.2 tpy. For Unit 2, the cost of implementing SNCR is estimated at $920,000 and is projected to reduce NO_x emissions by 114.4 tpy.

2.3.2 Flue Gas Recirculation

The estimated capital cost to retrofit an FGR system is based on budgetary equipment costs provided by a prospective equipment vendor. Estimated annual costs for this alternative include capital recovery charges, additional parasitic electrical charges for the recirculation fan, and additional fuel charges associated with the heat rate penalty resulting from decreased combustion efficiency. For annualization of the capital cost for each alternative, the remaining useful life/plant life was set as 30 years beyond the emission control system installation date. This estimated useful equipment life is conservative since the currently projected retirement date of the Station is 2049 (i.e., 24 years after conversion of North Valmy Unit 1 to natural gas firing).

Utilizing the budgetary equipment costs provided by a prospective equipment vendor in evaluating FGR as a potential control measure at both Valmy units, a cost-effective value of $9,801/ton and $8,712/ton is estimated for Unit 1 and 2, respectively. The total annual cost of implementing FGR on Unit 1 is estimated at $840,000 and is projected to reduce NO_x emissions by 86.2 tpy. For Unit 2, the cost of implementing FGR is estimated at $1,000,000 and is projected to reduce NO_x emissions by 114.4 tpy.

2.3.3 Selective Catalytic Reduction

Capital and annualized costs for SCR were estimated using USEPA's Control Cost Manual and employing a retrofit factor of 1.0. The remaining useful life/plant life was conservatively set as 30 years beyond the emission control system installation date for annualization of the capital cost for each alternative, recognizing that the unit may be retired sooner than 30 years based on an anticipated 2049 retirement date. Cost effectiveness for each alternative was estimated using the projected station output and corresponding uncontrolled emission levels associated with the 2028 projection.

Utilizing the Control Cost Manual spreadsheet in evaluating SCR as a potential control measure at both Valmy units, a cost-effectiveness value of $13,122/ton and $10,903/ton is estimated for Unit 1 and 2, respectively. The total annual cost of implementing SCR on Unit 1 is estimated at $3.53M and is projected to reduce NO_x emissions by 269.3 tpy. For Unit 2, the cost of implementing SCR is estimated at $3.90M and is projected to reduce NO_x emissions by 357.7 tpy.

Table 2-3: Valmy Four-Factor Analysis Cost-Effectiveness Summary

Control	Unit	Baseline Emissions	Tons Reduced	Total Annualized Costs	Cost – Effectiveness
SNCR	1	344.6 tpy NO_x	86.2 tpy NO_x	$840,000	$9,740/ton
	2	457.8 tpy NO_x	114.4 tpy NO_x	$920,000	$8,018/ton
FGR	1	344.6 tpy NO_x	86.2 tpy NO_x	$840,000	$9,801/ton
	2	457.8 tpy NO_x	114.4 tpy NO_x	$1,000,000	$8,712/ton
SCR	1	344.6 tpy NO_x	269.3 tpy NO_x	$3.53 Million	$13,122/ton
	2	457.8 tpy NO_x	357.7 tpy NO_x	$3.90 Million	$10,903/ton

2.4 Time Necessary for Compliance

NV Energy intends to convert both Unit 1 and Unit 2 at the North Valmy Generating Station from coal to natural gas-firing upon issuance of a permit modification. Subject to these approvals, conversion on one unit would occur as soon as late 2025 followed by the second unit in early 2026, allowing for one unit to be operational to meet system reliability needs during the conversion of the units and maintain availability for peak summer run conditions. For controls considered for Valmy Units 1 and 2 an estimated 36 months, from the effective date of EPA approval of the Nevada Regional Haze SIP, would be needed to fully implement SNCR, FGR or SCR. Delays in permit approvals, supply chain, or similar considerations could potentially extend this time. Understanding these potential constraints, it is still reasonably anticipated that compliance with any mandated reduction in NO_x emissions at North Valmy Station would be achieved before the fourth quarter of 2028 (the end of the Second Planning Period).

2.5 **Energy and Non-Air Quality Environmental Impacts**

Both SNCR and SCR utilize some form of ammonia as a reagent to promote the conversion of NO_x to elemental nitrogen and water. As a result of imperfect mixing between the flue gas and the reagent, a greater than stoichiometric amount of reducing agent must be injected for the NO_x reduction target to be achieved. The excess ammonia remains unreacted in the process and is emitted out the stack as ammonia "slip". Ammonia emissions associated with either SCR or SNCR are typically between 2 to 10 ppm. Ammonia for these processes can be provided using either anhydrous ammonia, aqueous ammonia, or urea. Storage and use of these forms of ammonia, especially anhydrous ammonia, can have significant safety concerns. Facilities that use anhydrous ammonia, or aqueous ammonia solution at concentrations greater than 20% are subject to additional accident prevention and emergency response plan development requirements under Nevada's Chemical Accident Prevention Program. The maximum allowable concentration of ammonia in aqueous solutions used at NV Energy facilities is 19%.

Retrofitting FGR or SCR to either North Valmy Unit 1 or 2 would be expected to result in an increase in the parasitic electrical load of the station. FGR systems require the use of an additional fan to carry boiler flue gas from the stack or breeching back to the combustion zone of the boiler. SCR systems require that auxiliary power be supplied to dilution fans for mixing air with the ammonia reducing agent and to pump ammonia across the vaporizer. In addition, placement of the SCR catalyst grid in the exhaust flow path of the boiler causes backpressure which must be overcome by supplying additional power to the existing flue gas fan systems. These increases in energy use are reflected in the economic analysis as one of the operating costs for FGR and SCR. The increased energy use, water use, and waste generation have all been accounted for in the economic assessment of these alternatives summarized previously.

2.6 **Remaining Useful Life of the Source**

For the purposes of the economic analysis, it has been assumed that both North Valmy Unit 1 and Unit 2 continue to operate at least 30 years after any of the technically feasible control alternatives were to be implemented, recognizing that the unit may be retired sooner than 30 years based on 2049 being the currently anticipated retirement date of the Station.

2.7 **Reasonable Progress Control Determination**

Based on the four statutory factors applied to the conversion of North Valmy Generating Station to natural gas firing, NDEP concludes that control measures for the reduction of NO_x are necessary to make reasonable progress. NDEP finds that SNCR, and FGR, are both cost effective and below the $10,000/ton threshold, SNCR being the most cost-effective, therefore SNCR and its associated NO_x limit are necessary to achieve reasonable progress. However, SCR and FGR are acceptable alternatives so long as the 0.102 lb/MMBtu emission limit is being met. NDEP is also requiring the continued use of low NO_x burners on both Units as necessary to meet reasonable progress. The existing baghouse and air atomized ignitors used to control PM_{10} for both Units and the spray dryer with lime slurry used to control SO_2 for Unit 2 are no longer deemed necessary since the conversion to pipeline quality natural gas will reduce PM_{10} and SO_2 emissions so that these controls are no longer cost effective.

NDEP is submitting the following controls, emission limits, and associated requirements, for approval into the SIP as measures necessary to make reasonable progress during the second implementation period of Nevada's Regional Haze SIP (Table 2-4). Table 2-4 replaces Table 5-9 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023.

These emission limits and associated requirements, listed in regulation R138-24, are incorporated into the SIP by reference. The regulation associated with North Valmy Generating Station's reasonable progress requirements can be found in Appendix C.

Table 2-4: North Valmy Regulation Incorporated by Reference

North Valmy Generating Station, Regulation R138-24		
	Citation	Regulatory Condition
Unit 1 (System 01 – Unit #1 Boiler)		
NO_x	Section 1.2(b)	Emission limit of 0.1029 lb/10^6 Btu, 30-day rolling average, controlled by permanent use of only pipeline quality natural gas as fuel, Low NO_x burners, and one of the following: selective noncatalytic reduction, flue gas recirculation, or selective catalytic reduction
	Section 1.3	Monitoring, Recordkeeping, Reporting
	Sections 1.4, 1.5	Compliance timeline
Unit 2 (System 02 – Unit #2 Boiler)		
NO_x	Section 1.2(b)	Emission limit of 0.1029 lb/10^6 Btu, 30-day rolling average, controlled by permanent use of only pipeline quality natural gas as fuel, Low NO_x burners, and one of the following: selective noncatalytic reduction, flue gas recirculation, or selective catalytic reduction.
	Section 1.3	Monitoring, Recordkeeping, Reporting.
	Sections 1.4, 1.5	Compliance timeline.

2.7.1 **Discussion of North Valmy Generating Station Four-Factor Outcome**

NV Energy's four-factor analysis relies on an emissions baseline derived from the annual average of emissions reported in 2016 through 2018. The emission reductions resulting from the conversion of both units to natural gas firing and the installation of SNCR or FGR are shown below in Table 2-5. Table 2-5 replaces Table 5-10 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023. By the end of 2028, or the end of the second implementation period, 1,144 tpy of NO_x reductions, 2,309 tpy SO_2 reductions, and 16.4 tpy of PM_{10} reductions are expected from the conversion to natural gas firing and the installation of controls at both Valmy units, amounting to a total of 3,469 tpy reductions of visibility impairing pollutants.

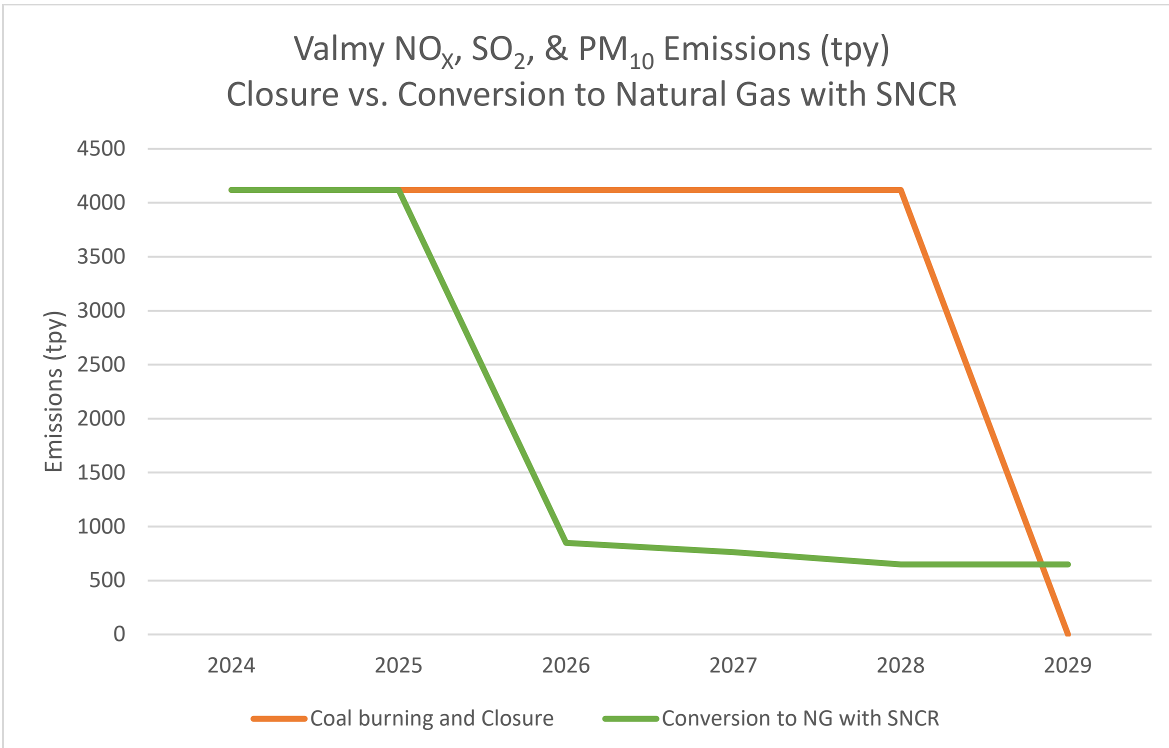
Table 2-5: Valmy Modeling vs. Final Emission Reductions During Second Round in TPY

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		Baseline Emissions	Emissions after Controls	Emission Reductions
Unit 1					
NO_x	785		796	259	537
SO_2	1,850		1,812	2	1810
PM_{10}	22		22	19	3
Unit 2					
NO_x	798		950	343	607
SO_2	431		501	2	499
PM_{10}	55		38	25	13
Total NO_x	1,583		1746	602	1144
Total SO_2	2,281		2313	4	2309
Total PM_{10}	77		60	44	16

Note: Negative values reflect annual emissions increases.

With the expected conversion to natural gas firing at the end of 2025 and installation of controls for Valmy Unit 1 by the end of 2026 and Unit 2 in 2027, emission levels are expected to decrease prior to when they would have if Valmy closed in 2028. The emission reductions resulting from the conversion of both units to natural gas firing and the installation of SNCR or FGR compared to closure are shown below in Figure 2-1. The reduced emission from the conversion could equal up to 10,095 tons of total visibility impairing pollutants by the end of the second implementation period. Reasonable progress goals are updated in Chapter 5 to account for these new emission reductions.

Figure 2-1: Valmy Combined Emissions, Closure vs. Conversion to Natural Gas with SNCR



3. RECONSIDERATION OF TRACY UNIT 4 PIÑON PINE

3.1 Unit Description

NV Energy's Tracy Generating Station is an electric generating facility located at 1799 Waltham Way, Exit 32, Sparks, Nevada approximately 81 kilometers (km) east of the Desolation Wilderness Class I area in El Dorado County, CA. This revision addresses Tracy Unit 4 Piñon Pine, a pipeline natural gas-fired combined cycle unit with steam injection.

3.2 Updated Four-Factor Analysis Summary

NV Energy submitted a revised four-factor analysis to include the removal of closure at the Tracy Unit 4 Piñon Pine. Table 3-1 outlines the files referenced for the Tracy Generating Station, documents used in the original reasonable progress determination can be found in the Regional Haze SIP submitted on August 12, 2022, while documents used for the revised reasonable progress determination can be found in Appendices A and B. For the purposes of the new control determination for Tracy, NDEP is relying on the updated four-factor analyses included in Appendix B of this SIP revision. Table 3-1 replaces Table 5-11 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023.

All major emission units currently in operation at the Tracy Generating Station that were considered in the facility's original four-factor analysis are summarized in Table 3-2. Table 3-2 replaces Table 5-12 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023. No changes were deemed necessary, and Table 3-2 is being submitted with its original content.

Table 3-1: Location of Four-Factor Analysis Documents for Tracy

Full Document Title	Shortened Document Title	Date	Document Location
Regional Haze Reasonable Further Progress Four Factor Analysis	*NVE Analysis*	March 13, 2020	SIP submitted on 8/12/2022
RE: Response to Request for Additional Information	*Response Letter 1*	July 8, 2020	SIP submitted on 8/12/2022
RE: Response to a Second Follow-up Request for Additional Information	*Response Letter 2*	January 15, 2021	SIP submitted on 8/12/2022
RE: Response to a Third Follow-up Request for Additional Information	*Response Letter 3*	April 16, 2021	SIP submitted on 8/12/2022
RE: Response to a Fourth Follow-up Request for Additional Information	*Response Letter 4*	May 7, 2021	SIP submitted on 8/12/2022
RE: Response to a Fifth Follow-up Request for Additional Information (Valmy specific)	*Response Letter 5.1*	August 27, 2021	SIP submitted on 8/12/2022
RE: Response to a Fifth Follow-up Request for Additional Information (Tracy specific)	*Response Letter 5.2*	October 11, 2021	SIP submitted on 8/12/2022
RE: Response to a Sixth Follow-up Request for Additional Information	*Response Letter 6*	April 29, 2022	SIP submitted on 8/12/2022
RE: Response to a Seventh Follow- up Request for Additional Information	*Response Letter 7*	May 27, 2022	SIP submitted on 8/12/2022
RE: NV Energy Response to an Eighth Follow-Up Request for Additional Information	*Response Letter 8*	August 5, 2022	SIP submitted on 8/12/2022
Regional Haze Reasonable Further Progress: Updated Four Factor Analysis NV Energy North Valmy and Tracy Generating Stations	*NV Energy's four-factor analysis*	March 2024	Appendix B
Class I Air Quality Operating Permit	Permit		A.2
Nevada Regulation	*Regulation*	September 17, 2024	Appendix C
RE: Response to Request for Additional Information Regional Haze Reasonable Further Progress: Updated Four Factor Analysis NV Energy North Valmy and Tracy Generating Stations	*Response Letter 9*	July 24, 2024	Appendix F

Table 3-2: List of Units at Tracy

NDEP Unit ID	NVE Unit ID	Description (and Nominal Rating)
Unit 3	Unit 3	Steam Boiler (MG) 113 MW
Unit 5	Clark Mountain 3	GE EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)
Unit 6	Clark Mountain 4	GE 7EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)
Tracy Unit 4 Piñon Pine	Piñon Pine 4	GE 6FA NG Combined Cycle Combustion Turbine 107 MW (+23 MW Duct Burners)
Unit 32	Unit 8	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 MMBtu/hr duct burners
Unit 33	Unit 9	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 MMBtu/hr duct burners

Tracy Unit 4 Piñon Pine was evaluated for potential new control measures for NO_x emissions considering the four statutory factors. Potential new control measures for SO_2 and PM_{10} were not considered at the Tracy Generating Station, as all units burn natural gas, resulting in low annual emissions for SO_2 and PM_{10}.

Currently, the Tracy Unit 4 Piñon Pine turbine uses steam injection to partially quench the heat of combustion to control NO_x emissions to approximately 41 ppm at 15% O_2 (2016-2018 average). NDEP considers the continued use of this control measure to control NO_x emissions as necessary to achieve reasonable progress.

3.2.1 **Baseline Emissions**

In NV Energy's initial four-factor analysis for Tracy Generating Station baseline emissions were derived from the annual average of emissions from 2016 through 2018. Table 3-3 outlines the baseline emission for units 5, 6, 32, and 33. Table 3-3 replaces Table 5-13 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023. No changes were deemed necessary, and Table 3-3 is being submitted with its original content.

Table 3-3: Tracy Four-Factor Analysis Baseline Emissions for Units 5, 6, 32, and 33

Unit ID	Average NO_x Emissions (tpy)	Average SO_2 Emissions (tpy)	Average PM_{10} Emissions (tpy)
Unit 5	12.0	0.3	1.0
Unit 6	10.6	0.2	0.8
Unit 32	38.5	4.0	24.3
Unit 33	37.5	4.0	23.8

For the purpose of NV Energy's four-factor analysis for the Tracy Generating Station, baseline emissions were adjusted to reflect the annual average of emissions observed from 2016 through 2020. Emissions data for 2019 and 2020 were incorporated into the baseline emissions for Units 3 and 4 Piñon Pine as they became available and were included in later Response Letters submitted by NV Energy. Tables 3-4 and 3-5 show the baseline emissions assumed for SO_2, NO_x, and PM_{10} emissions at Units 3 and 4 Piñon Pine. Table 3-4 replaces Table 5-14 and Table 3-5 replaces Table 5-15 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023. No changes were deemed necessary and both Tables 3-4 and 3-5 are being submitted with their original content.

Table 3-4: Tracy Four-Factor Analysis Baseline Emissions for Unit 3

	Unit 3 Emissions (tpy)				
Year	**2016**	**2017**	**2018**	**2019**	**2020**
Total Annual NO_x	77	61	114	230	210
2016-2018 Average	84				
2016-2020 Average	138				

Table 3-5: Tracy Four-Factor Analysis Baseline Emissions for Tracy Unit 4 Piñon Pine

	Tracy Unit 4 Piñon Pine Emissions (tpy)				
Year	**2016**	**2017**	**2018**	**2019**	**2020**
Total Annual NO_x	190	182	269	315	293
2016-2018 Average	213				
2016-2020 Average	250				

3.2.2 Identification of Technically Feasible Controls

For Tracy Unit 4 Piñon Pine at the Tracy Generating Station, NV Energy identified SCR and DLN Combustors as technically feasible control measures in controlling NO_x emissions. Selective non-catalytic reduction is not technically feasible for a combustion turbine because the exhaust temperatures are too low.

Since all units at the Tracy Generating Station are natural gas fired, potential additional SO_2 and PM_{10} control measures were not evaluated as the use of natural gas is considered as an existing effective control in controlling SO_2 and PM_{10} emissions. SO_2 and PM_{10} emissions at all units are low and would likely not result in a cost- effective add-on control for SO_2 and PM_{10} emissions that would be necessary to achieve reasonable progress if a four-factor analysis were conducted.

3.3 Cost of Compliance

A summary of the cost-effectiveness values for each technically feasible control technology considered at Tracy Generating Station is provided in Table 3-6. Table 3-6 replaces Table 5-16 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023. NDEP is relying on the original determination for Unit 3 which showed that all potential control measures for Unit 3 are not cost-effective or needed for reasonable progress.

3.3.1 Dry Low NO_x Combustor

The capital costs for a DLN combustor conversion are based on a 2010 budgetary estimate provided by General Electric (GE) for a DLN 2.6 combustor retrofit specific to this turbine. GE verified to NV Energy that this estimate was currently still valid after adjusting for inflation. This GE DLN equipment cost estimate was escalated to 2024 dollars using the Chemical Engineering Plant Cost Index (CEPCI) as recommended in USEPA's cost manual. Installation and other direct and indirect capital costs were based on GE's estimates or standard factors from USEPA cost manual and are also in 2024 dollars. GE estimates that this turbine's electrical generating capacity will decrease approximately 3.5% with DLN combustors verses the current steam injection. The conversion also decreases the efficiency of the turbine – which requires more fuel use to generate the same electricity. However, not using steam injection saves fuel use. To estimate the net overall cost impacts of these factors, NV Energy's Resource Planning

Department used the PROMOD software model to estimate the changes in operating costs associated with these impacts of a DLN conversion. There are other types of operating costs associated with conversion of this unit to DLN burners which NV Energy has not quantified, and if included, would further increase the costs of this control option. These include increased costs from the discontinuation of steam injection which impacts the plant's water balance.

Utilizing the 2010 budgetary estimate provided by General Electric (GE in evaluating DLN combustors as a potential control measure at Tracy Unit 4 Piñon Pine, a cost-effectiveness value of $13,535/ton is estimated. The total annual cost of implementing DLN combustors on Tracy Unit 4 Piñon Pine is estimated at $2.15M and is projected to reduce NO_x emissions by 158.5 tpy.

3.3.2 Selective Catalytic Reduction

The capital cost estimate for SCR for this turbine is based on a detailed price proposal provided to NV Energy in December 2019 by an SCR vendor, CECO Environmental/Peerless Manufacturing Co. The vendor's cost proposal covers the equipment costs for the SCR retrofit, ammonia injection skid, and ammonia storage. An estimated cost for installation was also included. NV Energy additionally estimated the costs of ancillary equipment not in the vendor's quote and indirect installation costs using standard factors in USEPA's Control Cost Manual SCR chapter. SCR capital costs were escalated to 2024 dollars using the CEPCI index. Annual operating costs associated with the use of SCR are based on the methodologies in the USEPA Control Cost Manual SCR chapter and also account for the capacity loss costs associated with a derate of the turbine due to the additional pressure drop caused by the SCR catalyst.

Utilizing the price proposal provided to NV Energy in December 2019 by an SCR vendor, CECO Environmental/Peerless Manufacturing Co., in evaluating SCR as a potential control measure at Tracy Unit 4 Piñon Pine, a cost-effectiveness value of $6,053/ton is estimated. The total annual cost of implementing SCR on Tracy Unit 4 Piñon Pine is estimated at $1.36M and is projected to reduce NO_x emissions by 225 tpy.

Table 3-6: Tracy Four-Factor Analysis Cost-Effectiveness Summary

Control	Unit	Baseline Emissions	Tons Reduced	Total Annualized Costs	Cost – Effectiveness
Dry Low NO_x Combustor	Tracy Unit 4 Piñon Pine	250 tpy NO_x	158.5 tpy NO_x	$2,150,000	$13,535/ton
SNCR	3	138 tpy NO_x	35 tpy NO_x	$474,641	$13,561/ton
SCR	Tracy Unit 4 Piñon Pine	250 tpy NO_x	225 tpy NO_x	$1,360,000	$6,053/ton
	3	138 tpy NO_x	124 tpy NO_x	$1,387,040	$11,186/ton

3.4 **Time Necessary for Compliance**

For controls considered for Tracy Unit 4 Piñon Pine an estimated 36 months, from the effective date of EPA approval of the Nevada Regional Haze SIP, would be needed to fully implement SCR. After Nevada's SIP approval, NV Energy would need time for design, permitting, procurement, installation, and startup of either of the two alternative NO_x control options for Tracy Unit 4 Piñon Pine. Additionally, installation of either of the above control options would require that the combustion turbine be out of service, which requires coordinating for the unit's outage to accommodate regional electrical needs and other regionally affected utilities. Given these considerations in addition to prioritizing the Valmy conversion and NO_x controls that will allow for cessation of coal-fired generation and more immediate emission reductions, it is still reasonably anticipated that compliance with any mandated reduction in NO_x emissions for Tracy Unit 4 Piñon Pine would be achieved before the fourth quarter of 2028 (the end of Second Decadal Review period).

3.5 **Energy and Non-Air Quality Environmental Impacts**

The DLN combustor conversion would have a negative impact on the plant's water balance and result in a wastewater stream that would require treatment or disposal. Currently, the steam injection system is integrated into the overall plant water balance. Process wastewater is used to produce demineralized water for use in the steam injection system. Elimination of steam injection on the unit would require additional investment in the water treatment system to dispose of the excess wastewater. A DLN conversion will also decrease the electrical generation of the turbine because of the decreased mass flow through the turbine's compressor section.

Implementation of SCR would result in an increase in the parasitic electrical load of the station. Placement of the SCR catalyst grid in the exhaust flow path of the heat recovery steam generator would cause back pressure on the turbine which increases the parasitic electrical load of the station. This increased energy use is reflected in the economic analysis as one of the operating costs for SCR. Additionally, there would be an increased energy demand for vaporizing and injecting the ammonia. SCR utilizes some form of ammonia as a reagent to promote the conversion of NO_x to elemental nitrogen and water. As a result of imperfect mixing between the flue gas and the reagent, a greater than stoichiometric amount of reducing agent must be injected for the NO_x reduction target to be achieved. The excess ammonia remains unreacted in the process and is emitted out the stack as ammonia "slip". Ammonia emissions associated with SCR are typically between 2 to 10 ppm. Ammonia for these processes can be provided using either anhydrous ammonia, aqueous ammonia, or urea. Storage and use of these forms of ammonia, especially anhydrous ammonia, can have significant safety concerns. Facilities that use anhydrous ammonia, or aqueous ammonia solution at concentrations greater than 20% are subject to additional accident prevention and emergency response plan development requirements under Nevada's Chemical Accident Prevention Program. The maximum allowable concentration of ammonia in aqueous solutions used at NV Energy facilities is 19%.

3.6 **Remaining Useful Life of the Source**

For the purposes of the economic analysis, it has been assumed that Tracy Unit 4 Piñon Pine will continue to operate at least 30 years after any of the technically feasible control alternatives were to be implemented, recognizing that the unit may be retired sooner than 30 years based on the currently anticipated 2049 retirement date for the station.

3.7 **Reasonable Progress Control Determination**

Based on the four statutory factors, NDEP concludes that the SCR control measure evaluated for the Tracy Generating Station is necessary to make reasonable progress.

As stated above, NDEP is relying on the continued use of existing NO_x controls at Units 3, 5, 6, 32, and 33 to make reasonable progress.

NDEP is submitting the following controls, emission limits, and associated requirements, for EPA approval into the SIP as measures necessary to make reasonable progress during the second implementation period of Nevada's Regional Haze SIP (Tables 3-7, and 3-8). Table 3-7 replaces Table 5-17 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023. NDEP is relying on Section 5.2 of NV Energy's four-factor analysis (Appendix B) and *NV Energy's Response Letter 9* for the derivation of the 0.0151 lb/MMBtu emission limit in Table 3-8.

These emission limits and associated requirements, listed in regulation R138-24, are incorporated into the SIP by reference. The regulation associated with Tracy Generating Station's reasonable progress requirements, can be found in Appendix C.

Table 3-7: Tracy Permit Conditions Incorporated by Reference

Tracy Generating Station, Permit No. AP4911-0194.04		
	Citation	Permit Condition
Unit 5 (System 05A – Clark Mountain Combustion Turbine #3)		
NO_x	IV.B.1.a	Emissions from **S2.006** shall be controlled by **Dry Low NO_x Burners** while combusting natural gas only. Emissions from **S2.006** shall be controlled with **Water Injection** while combusting No. 2 Distillate Fuel Oil under "Emergency" conditions defined in **B.2.c.** of this section. Note, these are not add-on controls.
	IV.B.3.f	The discharge of **NO_x** (oxides of nitrogen) to the atmosphere shall not exceed: (1) **9** parts per million by volume (ppmv) at 15 percent oxygen and on a dry basis, based on a 24-hour rolling period. (2) **42.0 pounds** per hour, based on a 720-hour rolling period. (3) **122.64** tons per year, based on a 12-month rolling period.
Unit 6 (System 06A – Clark Mountain Combustion Turbine #4)		
NO_x	IV.D.1.a	Emissions from **S2.007** shall be controlled by **Dry Low NO_x Burners** while combusting Pipeline Natural Gas only. Emissions from **S2.006** shall be controlled with **Water Injection** while combusting No. 2 Distillate Fuel Oil under "Emergency" conditions defined in **D.2.c.** of this section. Note, these are not add-on controls.
	IV.D.3.f	The discharge of **NO_x** (oxides of nitrogen) to the atmosphere shall not exceed: (1) **9** parts per million by volume (ppmv) at 15 percent oxygen and on a dry basis, based on a 24-hour rolling period. (2) **42.0 pounds** per hour, based on a 720-hour rolling period. (3) **122.64** tons per year, based on a 12-month rolling period.
Tracy Unit 4 Piñon Pine (System 07C – Tracy Unit #4 Piñon Pine Combustion Turbine)		
NO_x	IV.F.1	a. Emissions from S2.009 shall be controlled by a Steam Injection for control of NO_x. b. Emissions from S2.009.1 shall be controlled by Dry Low NO_x Burners. Note, these are not add-on controls.
Unit 32 (System 32 – Combined Cycle Combustion Turbine Circuit No. 8)		
NO_x	IV.L.1.a	NO_x emissions from **S2.064 and S2.065** shall be controlled by a **Selective Catalytic Reduction (SCR)**. The SCR shall utilize Ammonia Injection into the SCR at a volume specified by the manufacturer.
	IV.L.3.g	The discharge of **NO_x** to the atmosphere shall not exceed **2.0** parts per million by volume (ppmv) at 15 percent oxygen on a dry basis, based on a 3-hour rolling period.
Unit 33 (System 33 – Combined Cycle Combustion Turbine Circuit No. 9)		
NO_x	IV.M.1.a	NO_x emissions from **S2.066 and S2.067** shall be controlled by a **Selective Catalytic Reduction (SCR)**. The SCR shall utilize Ammonia Injection into the SCR at a volume specified by the manufacturer.
	IV.M.3.g	The discharge of **NO_x** to the atmosphere shall not exceed **2.00** parts per million (ppmv) by volume at 15 percent oxygen and on a dry basis, per 3-hour rolling period.
All Units – Monitoring, Recordkeeping, Reporting		
	V.A & V.C	Oxides of Nitrogen (NO_x) Continuous Emissions Monitoring System (CEMS) Conditions

Table 3-8: Tracy Regulation Incorporated by Reference

Tracy Generating Station, Regulation R138-24		
	Citation	Regulatory Condition
Tracy Unit #4 Piñon Pine (Combustion Turbine + Duct Burner)		
NO_x	Section 1.2(a)	Emission limit of 0.0151 lb/10^6 Btu, 30-day rolling average, controlled by permanent use of only pipeline quality natural gas as fuel, steam injection, and selective catalytic reduction.
	Section 1.3	Monitoring, Recordkeeping, Reporting.
	Section 1.4	Compliance timeline.

3.7.1 Discussion of Tracy Generating Station Four-Factor Outcome

NV Energy's four-factor analysis relies on an emissions baseline derived from the annual average of emissions reported in 2016 through 2020. The emission reductions resulting from the installation of SCR are shown below in Table 3-9. Table 3-9 replaces Table 5-18 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023. Although there is a slight difference in NO_x emissions between 2028OTBa2 and the Emissions After Controls inventories, as shown in Table 3-9, this is a result of different baseline emissions used and not because of reductions achieved from add-on controls considered in the four-factor analysis. By the end of 2028, or the end of the second implementation period, 225 tpy of NO_x reductions are expected from the installation of controls at Tracy Unit 4 Piñon Pine.

Nevada's SIP revision is also relying on existing controls, listed in Table 3-10, that effectively control visibility impairing pollutants. Table 3-10 replaces Table 5-19 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023. The continued use of these existing controls will be included in Nevada's Long-Term Strategy for the second implementation period, along with the current corresponding NO_x emission limits for each unit listed in the facility's current operating permit. These listed controls target NO_x emissions as the Tracy facility primarily burns pipeline natural gas.

Table 3-9: Tracy Modeling vs. Final Emissions Reductions During Second Round in TPY

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		Baseline Emissions	Emissions after Controls	Emission Reductions
Unit 3 Steam Boiler					
NO_x	114		84	84	0
SO_2	1		1	1	0
PM_{10}	2		2	2	0
Unit 4 Clark Mountain 3					
NO_x	22		12	12	0
SO_2	1		1	1	0
PM_{10}	1		1	1	0
Unit 5 Clark Mountain 4					
NO_x	20		11	11	0
SO_2	1		1	1	0
PM_{10}	1		1	1	0
Tracy Unit 4 Piñon Pine					
NO_x	267		250	25	225
SO_2	1		1	1	0
PM_{10}	7		7	7	0
Unit 8					
NO_x	40		39	39	0
SO_2	4		4	4	0
PM_{10}	24		24	24	0
Unit 9					
NO_x	40		38	38	0
SO_2	4		4	4	0
PM_{10}	24		24	24	0
Total NO_x	503		434	209	225
Total SO_2	12		12	12	0
Total PM_{10}	59		59	59	0

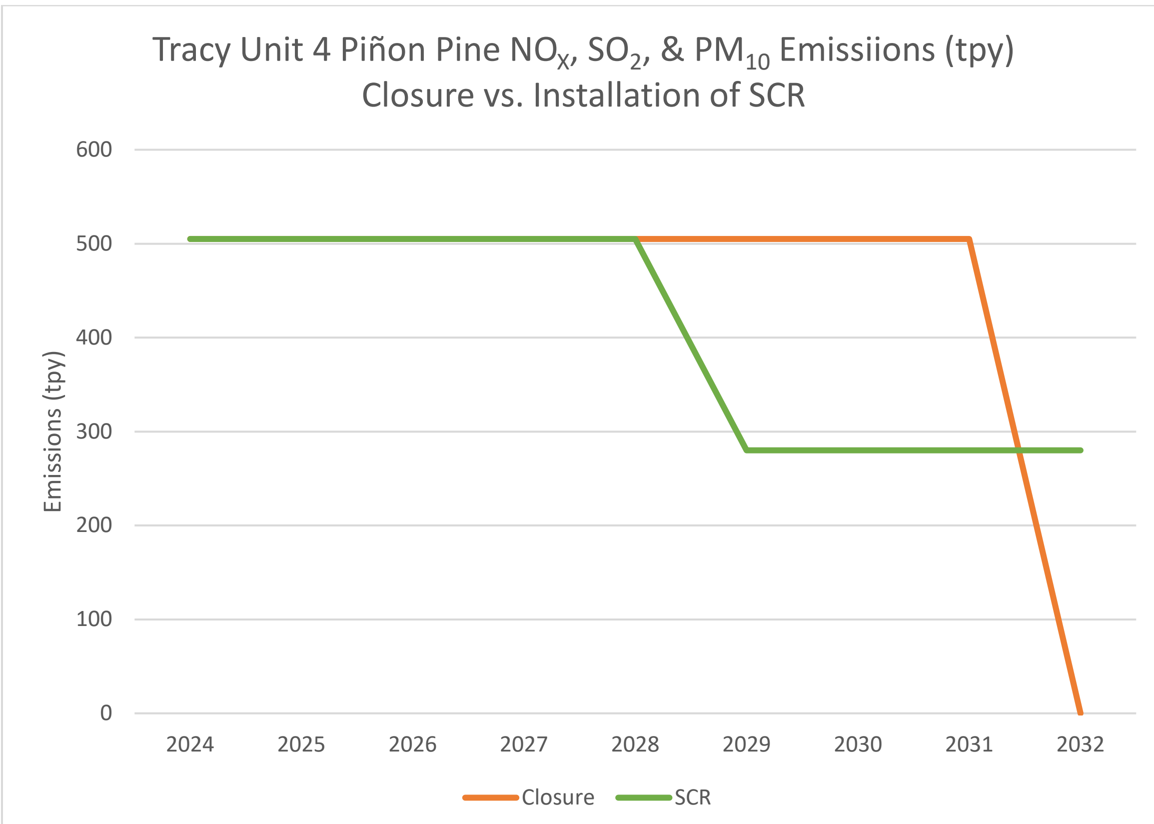
Table 3-10: Tracy Existing Controls for NO_x

Permit ID	NVE ID	Description and Nominal Rating	Current Control	Permitted NO_x Emission Limit
System 3	3	Steam Boiler (NG) 113 MW	Low-NO_x Burner	0.19 lb/MMBtu based on a 12-month rolling average
System 5	Clark Mountain 3	GE EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)	Dry Low NO_x combustors w/ NG (water injection if distillate)	9 ppmv based on a 24-hour rolling average
				42 lb/hr based on a 720-hour rolling average
				122.64 tpy based on a 12-month rolling average
System 6	Clark Mountain 4	GE 7EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)	Dry Low NO_x combustors w/ NG (water injection if distillate)	9 ppmv based on a 24-hour rolling average
				42 lb/hr based on a 720-hour rolling average
				122.64 tpy based on a 12-month rolling average
System 7	Piñon Pine 4	GE 6FA NG Combined Cycle Combustion Turbine 107 MW (+23 MW Duct Burners)	Steam injection	141.0 lb/hr, no more than 533.10 tpy based on a 12-month rolling average
System 32	Unit 8	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 MMBtu/hr duct burners	Low NO_x combustors, SCR, & Ox. catalyst	87.6 tons per year
				2 ppmv based on a 3-hour average
System 33	Unit 9	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 MMBtu/hr duct burners	Low NO_x combustors, SCR, & Ox. catalyst	87.6 tons per year
				2 ppmv based on a 3-hour average

With the installation of controls for Tracy Unit 4 Piñon Pine by the end of 2028 emission levels are expected to decrease prior to when they would have if Tracy Unit 4 Piñon Pine closed in 2031. Reductions from the closure of this unit would not have been observed during the second implementation period, ending in 2028, but observed in Nevada's third implementation period of the Regional Haze Rule. Because of this, expected reductions weren't quantified or assumed in Nevada's reasonable progress goals for the second implementation period. With the installation of SCR by 2028, more emission reductions will be realized during the second implementation period.

The emission reductions resulting from the installation of SCR compared to closure are shown below in Figure 3-10. The addition of controls could reduce emission by up to 675 tons of total visibility impairing pollutants between 2029 and 2031. Reasonable progress goals are updated in Chapter 5 to account for these new emission reductions.

Figure 3-1: Tracy Unit 4 Piñon Pine Combined Emissions, Closure vs. Installation of SCR



4. Updated Permits

4.1 Lhoist Apex Plant

The Lhoist Apex Plant is a lime production facility located in Clark County, NV just northeast of the Las Vegas metropolitan area and operates four horizontal rotary preheater lime kilns. On August 12, 2022, NDEP determined the implementation of LNBs at Kiln 1, and implementation of SNCR at Kilns 1, 3, and 4 as necessary to achieve reasonable progress during the second implementation period of Nevada's Regional Haze SIP. NDEP also considers the continued use of LNB on Kiln 3 and 4 as necessary to make reasonable progress as well. The requirements to achieve reasonable progress were established in the Apex Plant's Authority to Construct (ATC) Permit issued and enforced by the Clark County Department of Environment and Sustainability and incorporated by reference into Nevada's Regional Haze SIP.

Apex's ATC Permit expired 18 months after its original issue date of August 3, 2022, and was reissued by the Clark County Department of Environment and Sustainability on February 6, 2024. This permit will be renewed once more prior to final submittal of Nevada's 2024 Regional Haze SIP. All referenced permit conditions below remain the same as those in Nevada's SIP submitted on August 12, 2022 (Table 4-1). These conditions are incorporated by reference into Nevada's Regional Haze SIP Long-Term Strategy for the second implementation period as a source-specific SIP revision for approval. Pages with referenced conditions in the Apex Plant's Authority to Construct permit that NDEP is relying on to achieve reasonable progress for the second implementation period can be found in Appendix A.1.

Table 4-1: Apex Plant ATC Permit Conditions Incorporated by Reference

Apex Plant, Authority to Construct Permit for a Major Part 70 Source, Source ID: 3, Clark County DES		
	Citation	Permit Condition
Control Requirements (Facility-Wide)		
NO_X	2.2.1	The control requirements and the NO_X emission reductions proposed in the ATC are permanent and shall not be removed, changed, revised, or modified without the approval of the Nevada Division of Environmental Protection and USEPA upon becoming effective.
	2.2.2	Effective no later than two years after the USEPA's approval of the controls determination associated with the SIP, the permittee shall install and maintain **low- NO_X burners (LNB) on Kilns 1, 3 and 4** in order to achieve a reduction of **NO_X emissions** (EU: K102, K302, and K402).
	2.2.3	Effective no later than two years after the USEPA's approval of the controls determination associated with the SIP, the permittee shall install, operate, and maintain **selective non-catalytic reduction (SNCR) on Kilns 1, 3, and 4 (EUs: K102, K302, and K402) to achieve reduction of NO_X emissions**
Emission Limits (Facility-Wide)		
NO_X	3.2.1	Effective no later than two years after the USEPA's approval of the control's determination associated with the SIP, the permittee shall **limit total NO_X emissions from all operating kilns to 3.75 tons per day based on a consecutive 30-day average** (EUs: K102, K202, K302, and K402).
	3.2.2	Effective no later than two years after the USEPA's approval of the control's determination associated with the SIP, the permittee **shall limit the combined total NO_X emissions from all operating kilns to 3.59 lb/tlp based on a consecutive 12- month average** (EUs: K102, K202, K302, and K402)
Monitoring, Recordkeeping, and Reporting Requirements		
NO_X	4.1	Monitoring
	4.3.6 4.3.7	Recordkeeping
	4.4.7 4.4.8	Reporting and Notifications

4.2 Graymont Pilot Peak Plant

The Graymont Pilot Peak Plant is a lime production facility located in Elko County, NV and operates three horizontal rotary preheater lime kilns. NDEP determined that the continued use of LNBs at all three kilns is necessary to make reasonable progress. A compliance deadline of 240 days from issuance of the updated permit was set to allow for continuous emissions monitoring system (CEMS) requirements. This compliance date has been met by Pilot Peak. A minor revision of the Pilot Peak Class I Air Quality Operating Permit (AP3274-1329.03) was issued by the State of Nevada June 14, 2024. All referenced permit conditions below remain the same as those in Nevada's SIP submitted on August 12, 2022 (Table 4-2). These conditions are incorporated by reference into Nevada's Regional Haze SIP Long-Term Strategy for the second implementation period as a source-specific SIP revision for approval. Pages with referenced conditions in the Pilot Peak Plant's permit that NDEP is relying on to achieve reasonable progress for the second implementation period can be found in Appendix A.3.

Table 4-2: Pilot Peak Plant Permit Conditions Incorporated by Reference

Pilot Peak Plant, Permit No. AP3274-1329.03		
	Citation	Permit Condition
Kiln 1 (System 10 – Kiln #1 Circuit)		
NO_x	IV.I.1.a	Emissions from S2.031 through S2.033 shall be controlled by a baghouse (D-85) and Low- NO_x Burners.
	IV.I.3.b	The Permittee, within 240 days upon issuance of this operating permit, shall not discharge into the atmosphere from the exhaust stack of baghouse (D-85) the following pollutants in excess of the following specified limits: (1) Nevada Regional Haze SIP Limit – The discharge of NO_x to the atmosphere shall not exceed 101.4 pounds per hour, based on a 30-day rolling average period.
	V.B-C	NO_x (CEMS) Requirements for System 10 (S2.031, S2.032, and S2.033), System 13 (S2.036, S2.037, S2.038), and System 17 (S2.042, S2.043, S2.044)
	IV.I.4.q IV.I.4.u	Specific Monitoring, Recordkeeping, and Reporting Requirements
Kiln 2 (System 13 – Kiln #2 Circuit)		
NO_x	IV.L.1.a	Emissions from S2.036 through S2.038 shall be controlled by a baghouse (D-285) and Low- NO_x Burners.
	IV.L.3.b	The Permittee, within 240 days upon issuance of this operating permit, shall not discharge into the atmosphere from the exhaust stack of baghouse (D-285) the following pollutants in excess of the following specified limits: (1) Nevada Regional Haze SIP Limit – The discharge of NO_x to the atmosphere shall not exceed 107.4 pounds per hour, based on a 30-day rolling average period.
	V.B-C	NO_x (CEMS) Requirements for System 10 (S2.031, S2.032, and S2.033), System 13 (S2.036, S2.037, S2.038), and System 17 (S2.042, S2.043, S2.044)
	IV.L.4.q IV.L.4.u	Specific Monitoring, Recordkeeping, and Reporting Requirements
Kiln 3 (System 17 – Kiln #3 Circuit)		
NO_x	IV.Q.1.a	Emissions from S2.042 through S2.044 shall be controlled by a baghouse (D-385) and Low- NO_x Burners.
	IV.Q.3.b	The Permittee, within 240 days upon issuance of this operating permit, shall not discharge into the atmosphere from the exhaust stack of baghouse (D-385) the following pollutants in excess of the following specified limits: (1) Nevada Regional Haze SIP Limit – The discharge of NO_x to the atmosphere shall not exceed 143.7 pounds per hour, based on a 30-day rolling average period.
	V.B-C	NO_x (CEMS) Requirements for System 10 (S2.031, S2.032, and S2.033), System 13 (S2.036, S2.037, S2.038), and System 17 (S2.042, S2.043, S2.044)
	IV.Q.4.q IV.Q.4.u	Specific Monitoring, Recordkeeping, and Reporting Requirements

5. LONG-TERM STRATEGY

5.1 Cumulative Emissions Reductions

Significant emission reductions are expected to achieve reasonable progress for the second implementation period of Nevada's Regional Haze SIP. Emission reductions for all facilities conducting a four-factor analysis were estimated by both WRAP and NDEP. WRAP estimates were developed for modeling inventories, with 2028OTBa2 data using updated 2014 emissions. In NDEP's four-factor analyses calculations, baseline emissions were typically derived from more recent reporting years (e.g. average annual emissions from 2016 to 2018) and controlled emissions derived from the assumed control efficiency of any control that is cost-effective and necessary to achieve reasonable progress.

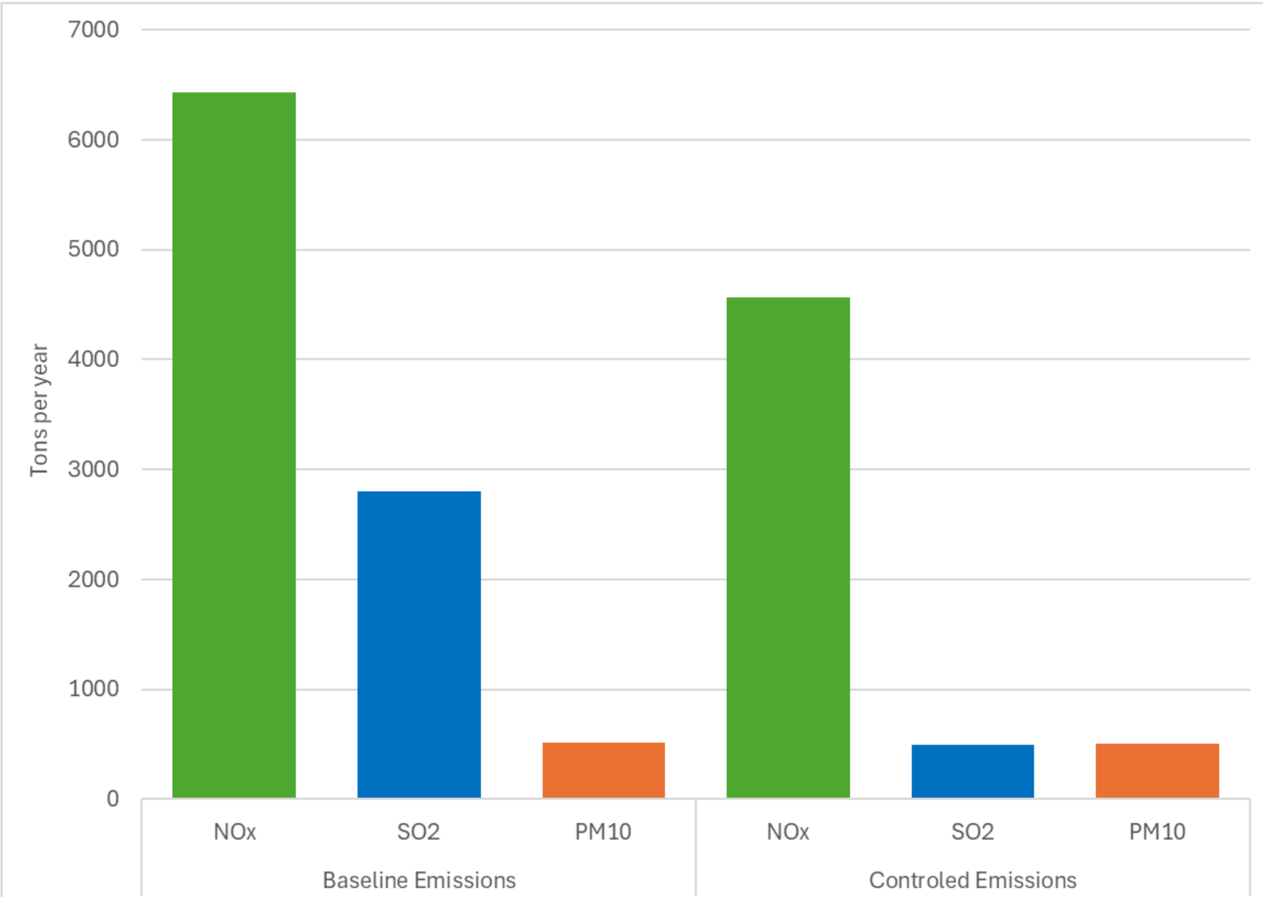
Emission reductions calculated from NDEP's four-factor analyses are more accurate than what was estimated for WRAP modeling and provide a better image of achieved emission reductions as a result of Nevada's efforts during the second implementation period. WRAP modeling inventories used less recent emissions data for the baseline and only estimates of controlled emissions. Table 5-1 compares the total emission reductions between baseline and controlled emissions for WRAP modeling and NDEP's four-factor analyses. Table 5-1 replaces Table 5-40 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023. Total emissions across the four-factor sources were estimated at 7,964 tpy in WRAP 2028OTBa2 modeling, while NDEP's four-factor data indicates total emissions across four-factor sources at 5,563 tpy. This translates to a difference of 2,401 tpy.

Figure 5-1 compares NDEP's calculation of baseline and controlled emissions among the sources in Nevada, considered for reasonable progress controls. Figure 5-1 replaces Figure 5-1 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023. SO_2 emissions show a total reduction of 2,309 tpy, NO_x emissions show a total reduction of 1,862 tpy, and PM_{10} emissions show a total reduction of 16 tpy. Referring to more current and accurate baseline emissions used in the four-factor analyses, Nevada expects a total reduction in primary visibility impairing pollutants (SO_2, NO_x, and PM_{10}) of 4,187 tpy as a result of the four-factor analyses conducted to achieve reasonable progress for the second round.

Table 5-1: Total Modeling vs. Final Emissions Reductions During Second Round in TPY

	WRAP Modeling		Four-Factor Analysis		
	2028OTBa2 Emissions		Baseline Emissions	Emissions after Controls	Emission Reductions
Valmy					
NO_x	1583		1746	602	1144
SO_2	2,281		2,313	4	2309
PM_{10}	77		60	44	16
Tracy					
NO_x	503		434	209	225
SO_2	11.5		12	12	0
PM_{10}	59		59	59	0
Apex					
NO_x	1,352		1164	671	493
SO_2	150		138	138	0
PM_{10}	8		59	59	0
Pilot Peak					
NO_x	523		515	515	0
SO_2	23		6	6	0
PM_{10}	54		93	93	0
Fernley					
NO_x	1,098		2568	2568	0
SO_2	126		334	334	0
PM_{10}	115		250	250	0
Total					
NO_x	5,059		6427	4565	1862
SO_2	2,592		2803	494	2309
PM_{10}	313		521	505	16
Grand Total	7,964		9,751	5,563	**4,187**

Figure 5-1: Baseline and Controlled Emissions Comparison for Reasonable Progress During the Second Implementation Period



Significant emissions reductions will be achieved through the installation of new control measures. Table 5-2 summarizes the expected emissions reductions resulting from the installation of reasonable progress control technologies. Table 5-2 replaces Table 7-1 from the Regional Haze SIP submitted on August 12, 2022, and partially withdrawn on July 27, 2023.

Table 5-2: Annual Emissions Reductions in Tons Resulting from Implementation of Reasonable Progress in Nevada

NO_x	SO_2	PM_{10}	Total
1,862	2,309	16	4,187

5.2 **Revised Reasonable Progress Goals**

5.2.1 Regional Scale Modeling of the LTS to Set the RPGS for 2028

The baseline 2028 visibility conditions (2028OTBa2) are projected at 7.764 dv during the most impaired days and 1.724 dv during the clearest days. Applying referenced scaling method with the revised four-factor analysis data to these model outputs calculate an updated RPG for the end of the Second Planning Period at Jarbidge WA of 7.758 dv during the most impaired days and 1.720 dv during the clearest days (Appendix D). Change in visibility improvement is small and lost in rounding (still 7.76 dv for most impaired days and 1.72 dv for clearest days). A comparison of the two visibility projections for Jarbidge WA in 2028 are provided in Table 5-3. Table 5-3 replaces Table 6-3 from the Regional Haze SIP submitted on August 12, 2022. This table was not included in the partial withdrawal on July 27, 2023, but is included in this revision to show that while the rounded values shown in the graphs remain the same there is a 0.001 dv projected decline in visibility during the most impaired days when compared to the 2022 RH SIP.

Table 5-3: 2028 Visibility vs. Proposed RPGs for Jarbidge WA

	2028OTBa2 RPG (dv)	2022 RH SIP RPG (dv)	2024 RH SIP Revised RPG (dv)	Rounded (dv)
Most Impaired Days	7.764	7.757	7.758	7.76
Clearest Days	1.724	1.720	1.720	1.72

5.2.2 URP Glidepath Check for Jarbidge WA

The URP glidepath, along with 2028 RPGs, at Jarbidge WA during the second implementation period is provided in Figure 5-2 and summarized in Table 5-4. Figure 5-2 and Table 5-4 replace Figure 6-4 and Table 6-4 from the Regional Haze SIP submitted on August 12, 2022. Figure 6-4 and Table 6-4 were not included in the partial withdrawal on July 27, 2023, but are being included in this revision since the content has changed. The 2028 RPG for Jarbidge WA during the 20 percent most impaired days is 7.76 deciviews. The below figure shows that visibility during the 20 percent most impaired days is expected to improve in 2028 (7.76 deciviews) compared to the 2000-2004 baseline conditions (8.73 deciviews). It also shows that the visibility conditions for the 20 percent clearest days in 2028 (1.72 deciviews) are expected to be better than the observed values for 20 percent clearest days from the 2000-2004 baseline condition (2.56 deciviews).

The glidepath assumes natural visibility conditions of 7.39 deciviews, including adjustments to account for international emissions and prescribed fire impacts. In order to achieve natural conditions by 2064, visibility projections during the 20 percent most impaired days must be 8.20

deciviews or below by 2028. NDEP's 2028 RPG for the 20 percent most impaired days of 7.76 deciviews confirms that visibility at Jarbidge WA is on track to achieve natural conditions by 2064.

Figure 5-2: Jarbidge WA Final URP Glidepath with 2028 Reasonable Progress Goals

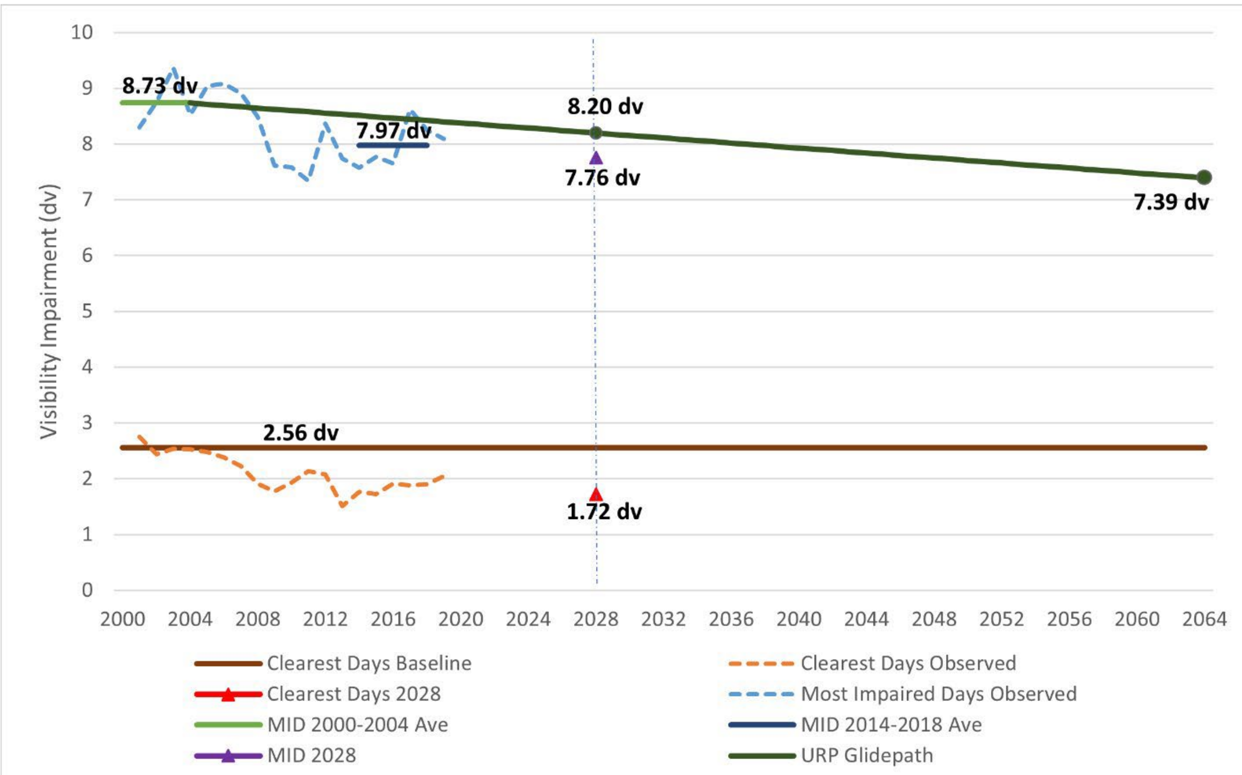


Table 5-4: Summary of Predicted Progress Toward 2028 Uniform Rate of Progress at JARB1 (Deciviews)

Class I Area	20% Most Impaired Days				20% Clearest Days		
	Most Impaired Days Baseline	2028 Adjusted URP	Baseline 2028 Visibility	2028 RPG	Clearest Days Baseline	2028 RPG	RPG Less Than Baseline?
Jarbidge WA	8.730	8.200	7.764	7.758	2.564	1.720	Yes

5.3 Source Retirement and Replacement Schedules

NDEP is no longer relying on closure of any units as part of its Long-Term Strategy for the Second Planning Period. As Nevada grows and new stationary sources are constructed, NDEP will continue to identify opportunities to retire or retrofit older sources in order to aid progress toward the national visibility goal. Nevada's continued implementation of new source review and prevention of significant deterioration requirements, with FLM involvement for Class I area impact review, will protect visibility progress made for the clearest days and will safeguard against Class I Area degradation.

6. FEDERAL LAND MANAGER CONSULTATION AND PUBLIC COMMENT

6.1 Federal Land Manager Consultation

40 CFR 51.308(i) of the RHR requires coordination between states and the FLMs. Nevada has provided agency contacts to the FLMs as required in 40 CFR 51.308(i)(1). A draft version of this revision was submitted to the National Parks Service (NPS), U.S. Fish and Wildlife Service (FWS), U.S. Forest Service (USFS), and the Bureau of Land Management (BLM) on April 14, 2024, for a 60-day review and comment period as required by 40 CFR 51.308 (i)(2). On June 4, 2024, staff from the NPS Air Resources Division hosted a regional haze consultation meeting with NDEP staff to discuss NPS input on the draft SIP. Representatives from the USFS, BLM, and USEPA Region 9 also attended. Official replies were received from the NPS on June 5th, the USFS on June 18th, the FWS on June 17th, and the BLM June 21st, 2024, and can be found in Appendix E.

The USFS, BLM and FWS did not provide formal comments on Nevada's Regional Haze SIP revision, however the USFS concurred with comments submitted by the NPS. The NPS formal response submitted on June 5th, 2024, included the following conclusions and recommendations.

> NPS analysis of SCR's potential to reduce NO_x emissions at North Valmy Units 1 and 2 finds cost-effectiveness meets the $10,000/ton threshold set by Nevada. The NPS recommends that NDEP require SCR for reasonable progress on both units.
>
> The NPS cost estimates are lower than those provided by NVE because:
>
> - Cost-effectiveness is highly sensitive to capacity utilization.
>   - The NPS analysis used more-recent, post-pandemic higher utilization data to reflect anticipated future utilization after IPC departs.
>   - If NDEP determines that SCR is not cost-effective on the basis of limited utilization, the NPS recommends inclusion of a federally enforceable limit on individual unit utilization to that effect.
> - In addition, NPS review:
>   - used higher Heat Input values than NVE,
>   - assumed that SCR could achieve a slightly lower emission rate based on 2023 CAMPD data,
>   - used the 2023 (instead of 2024) CEPCI (as advised by OAQPS), and
>   - used the 2023 cost of anhydrous ammonia reagent.

Detailed feedback provided by the NPS for NDEP on the draft revision to the SIP for the second planning period and supporting documents can be found in Appendix E.

6.2 Public Comment

(This section reserved for documentation of Public Comment)

7. REFERENCES

U.S. EPA 2003. Guidance for Tracking Progress under the Regional Haze Rule. EPA-454/B-03-004. September 2003.

U.S. EPA 2013. General Principles for 5-year Regional Haze Progress Reports. April 2013.

U.S. EPA 2018. Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. EPA-454/R-18-010. December 2018.

U.S. EPA 2019. Guidance on Regional Haze State Implementation Plans for the Second Implementation Period. EPA-457/B-19-003. August 2019.

U.S. EPA 2019. Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling. September 2019.

U.S. EPA 2020. Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. June 2020.

U.S. EPA 2021. Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period. July 2021.

Appendix A – Air Quality Permits Incorporated by Reference

Appendix A.1 Apex Plant, Lhoist North America

Appendix A.2 Tracy Generating Station, NV Energy

Appendix A.3 Pilot Peak Plant, Graymont

Appendix A.1 – Apex Plant, Lhoist North America

Provisions provided in the following ATC permit issued by Clark County Department of Environment and Sustainability for the Apex Plant are hereby incorporated and adopted into Nevada's Second Regional Haze SIP by reference. Provisions that are ~~struck-out~~ are not intended to be incorporated into the SIP by reference for approval or intended to be codified as part of Nevada's Second Regional Haze SIP. This reissued permit replaces the original ATC permit incorporated by reference into Nevada's SIP submitted on August 12, 2022.

DES
DEPARTMENT OF ENVIRONMENT AND SUSTAINABILITY
air quality desert conservation PROGRAM sustainability

4701 W. Russell Road 2nd Floor
Las Vegas, NV 89118-2231
Phone: (702) 455-5942 ♦ Fax: (702) 383-9994
Marci Henson, Director

AUTHORITY TO CONSTRUCT PERMIT FOR A MAJOR PART 70 SOURCE

SOURCE ID: 00003

Lhoist North America of Arizona Apex Plant
12101 North Las Vegas Boulevard
Las Vegas, Nevada 89165

ORIGINAL ISSUE DATE: August 3, 2022

REISSUE DATE: February 6, 2024

CURRENT ACTION: ATC Administrative Revision

Issued to:
Lhoist North America of Arizona, Inc.
2215B Renaissance Drive
Las Vegas, Nevada 89119

Responsible Official:
Casey Piland
Plant Manager
Phone: (205) 500-9702
Email: casey.piland@lhoist.com

NATURE OF BUSINESS:
SIC code 3274, "Lime Manufacturing"
NAICS code 327410, "Lime Manufacturing"

Issued by the Clark County Department of Environment and Sustainability in accordance with Section 12.4 of the Clark County Air Quality Regulations.

Santosh Mathew, Permitting Manager

~~EXECUTIVE SUMMARY~~

~~Lhoist North America of Arizona (LNA) is a manufacturer of lime and lime products. The legal description of the source location is T18S, R63E, Sections 23 and 26 in Apex Valley, County of Clark, State of Nevada. The Apex plant is situated in Hydrographic Area 216 (Garnet Valley), which is designated as an attainment area for 8-hour ozone (regulated through NO_x and VOC), PM_{10}, CO, and SO_2.~~

~~The LNA Apex Plant is a categorical source, as defined by AQR 12.2.2(j)(12). The plant is a major stationary source for PM_{10}, $PM_{2.5}$, NO_x, CO, SO_2, and a single HAP (HCl), and a minor source for total HAP and VOC. LNA is also a major source of greenhouse gases. The Apex operation includes mining and excavating, limestone handling and processing, solid fuel handling, lime storage silos, fuel storage tanks, and truck and railcar loading and transporting. Four rotary lime kilns are used to convert limestone to quicklime; these kilns can be fired by coal, coke, or natural gas.~~

~~LNA was selected as a participant for evaluation of the regional haze four-factor review and control determination ("four-factor analysis") for the second decadal implementation of the Long-Term Strategy of Nevada's Regional Haze State Implementation Plan (Nevada Regional Haze SIP). The Nevada Regional Haze SIP addresses all visibility-impairing pollutants (including PM_{10}, SO_2, and NO_x). The current SIP revision is for the second implementation period (2018–2028), and relies on the findings from the four-factor analysis to achieve reasonable progress in reducing the emissions of target pollutants by adopting additional control strategies. As a result of the four-factor analysis, LNA is only expected to address NO_x emissions with this ATC.~~

~~The table below summarizes the source potential to emit (PTE) (in units of tons per year) for each regulated air pollutant for all emission units addressed in the Part 70 Operating Permit.~~

~~Source-wide Potential to Emit~~ [1]

~~Pollutant~~	~~PM_{10}~~	~~$PM_{2.5}$~~	~~NO_x~~	~~CO~~	~~SO_2~~	~~VOC~~	~~HAP~~[2]	~~HAP~~[2] ~~(HCl)~~	~~GHG~~[3]
~~Tons/year~~	~~335.90~~	~~203.13~~	~~1,905.45~~ ~~1,399.45~~[4]	~~974.30~~	~~1,646.77~~	~~9.40~~	~~22.97~~	~~21.12~~	~~697,459~~

[1] ~~The PTE in this table is for informational purposes only.~~
[2] ~~Major source threshold for HAPs is 10 tons for any individual hazardous air pollutant or 25 tons for a combination of all HAPs.~~
[3] ~~Metric tons per year, CO_2e. GHG = greenhouse gas pollutants.~~
[4] ~~New NO_X PTE will be effective no later than two years after the EPA's approval of the control determination. NO_X PTE value results from the AQR 12.4 ATC Application (5/23/2022).~~

~~LNA is subject to 40 CFR Part 60, Subpart Y; 40 CFR Part 60, Subpart OOO; 40 CFR Part 60, Subpart IIII; 40 CFR Part 60, Subpart HH; 40 CFR Part 63, Subpart ZZZZ; and 40 CFR Part 63, Subpart AAAAA. By meeting the requirements of 40 CFR Part 60, Subpart IIII, the source also meets the requirements of 40 CFR Part 63, Subpart ZZZZ. The source is also subject to 40 CFR Part 51, Subpart P ("Protection of Visibility").~~

TABLE OF CONTENTS

LIST OF TABLES

Common Acronyms and Abbreviations

(These terms may be seen in the permit)

Acronym	Term
AQR	Clark County Air Quality Regulation
ATC	Authority to Construct
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
DAQ	Division of Air Quality
DES	Department of Environment and Sustainability
DOM	date of manufacture
dscf	dry standard cubic feet
dscm	dry standard cubic meter
EPA	U.S. Environmental Protection Agency
EU	emission unit
g/gr	gram
HAP	hazardous air pollutant
hp	horsepower
kW	kilowatts
LNB	low-NO_X burner
NAICS	North American Industry Classification System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_X	nitrogen oxides
NRS	Nevada Revised Statutes
NSPS	New Source Performance Standard
NSR	New Source Review
OP	Operating Permit
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
PM_{10}	particulate matter less than 10 microns in diameter
PSD	Prevention of Significant Deterioration
PTE	potential to emit
SIC	Standard Industrial Classification
SIP	Nevada Regional Haze State Implementation Plan for the second implementation period
SO_2	sulfur dioxides
tlp	tons of lime produced
tpd	tons per day
U.S.C.	United States Code
VMT	vehicle miles traveled
VOC	volatile organic compound

1.0 *EQUIPMENT*

1.1 EMISSION UNITS

1. This ATC consists of the affected emission units listed in Table 1-1. *[AQR 12.4 ATC Application (5/23/2022)]*

Table 1-1: List of Affected Emission Units

EU	Source EU Identifier	Description	Rating
K102	KN-01	Rotary Kiln 1	81.25 MMBtu/hr
K202	KN-02	Rotary Kiln 2	81.25 MMBtu/hr
K302	KN-03	Rotary Kiln 3	91.10 MMBtu/hr
K402	K4-KN-305	Rotary Kiln 4	281.25 MMBtu/hr

2.0 *CONTROLS*

2.1 CONTROL DEVICES

1. Effective no later than two years after Environmental Protection Agency (EPA) approval of the controls determination associated with the SIP, the additional control devices identified in Table 2-1 shall be installed. *[AQR 12.4 ATC Application (5/23/2022) & 40 CFR Part 51.308]*

Table 2-1: Add-on Controls for NO_X Reduction on Kilns

EU	Description	Control
K102	Kiln 1	LNB and SNCR
K302	Kiln 3	LNB and SNCR
K402	Kiln 4	LNB and SNCR

2.2 CONTROL REQUIREMENTS

1. The control requirements and the NO_x emission reductions proposed in the ATC are permanent and, upon becoming effective, shall not be removed, changed, revised, or modified without the approval of the Nevada Division of Environmental Protection and EPA.

2. Effective no later than two years after EPA's approval of the controls determination associated with the SIP, the permittee shall install and maintain low-NO_x burners (LNB) on Kilns 1, 3, and 4 to achieve a reduction of NO_x emissions (EU: K102, K302, and K402). *[AQR 12.4 ATC Application (5/23/2022) & 40 CFR Part 51.308]*

3. Effective no later than two years after EPA's approval of the controls determination associated with the SIP, the permittee shall install, operate, and maintain selective non-catalytic reduction (SNCR) on Kilns 1, 3, and 4 (EUs: K102, K302, and K402) to achieve reduction of NO_x emissions. *[AQR 12.4 ATC Application (5/23/2022) & 40 CFR Part 51.308]*

3.0 *LIMITATIONS AND STANDARDS*

3.1 OPERATIONAL LIMITS

1. ~~The permittee shall limit the lime throughputs in Kiln 1 and Kiln 2 to 109,500 tons each per any consecutive 12-month period (EUs: K102 and K202). *[APCHB Order on Appeal of Part 70 OP (10/15/2012)]*~~

2. ~~The permittee shall limit the total lime throughput in Kiln 3 to 146,000 tons per any consecutive 12-month period (EU: K302). *[APCHB Order on Appeal of Part 70 OP (10/15/2012)]*~~

3. ~~The permittee shall limit the lime throughput in Kiln 4 to 1,350 tons per day, based on a calendar month average, and to 475,000 tons per any consecutive 12-month period (EU: K402). *[APCHB Order on Appeal of Part 70 OP (10/15/2012)]*~~

3.2 EMISSION LIMITS

1. Effective no later than two years after EPA approval of the controls determination associated with the SIP, the permittee shall limit total NO_x emissions from all operating kilns to 3.75 tons per day based on a consecutive 30-day average (EUs: K102, K202, K302, and K402). *[AQR 12.4 ATC Application (5/23/2022) & 40 CFR Part 51.308]*

2. Effective no later than two years after EPA approval of the controls determination associated with the SIP, the permittee shall limit the combined total NO_x emissions from all operating kilns to 3.59 lb/tlp based on a consecutive 12-month average (EUs: K102, K202, K302, and K402). *[AQR 12.4 ATC Application (5/23/2022) & 40 CFR Part 51.308]*

4.0 *PROVISIONAL OPERATING CONDITIONS*

4.1 MONITORING

1. Effective no later than two years after EPA approval of the controls determination associated with the SIP, in order to demonstrate continuous, direct compliance with the Kilns 1–4 (EUs: K102, K202, K302, and K402) emissions limits for NO_x specified in Sections 3.2.1 and 3.2.2, the permittee shall calibrate, maintain, operate, and certify the continuous emissions monitoring system (CEMS). *[AQR 12.4.3.4(a)(10)]*

2. Effective no later than two years after EPA approval of the controls determination associated with the SIP, the permittee shall operate the CEMS according to the provisions of 40 CFR Part 60, Subpart A, Appendices B & F, as applicable at all times that Kilns 1-4 (EUs: K102, K202, K302, and K402) are in use except during malfunctions, maintenance, calibration, and repairs of the CEMS. *[AQR 12.4.3.4(a)(10)]*

    a. The CEMS shall include a data acquisition and handling system. *[AQR 12.4.3.4(a)(10)]*

3. The permittee shall develop and implement a quality control program with written procedures, as required by 40 CFR Part 60, Appendix F.

4. Effective no later than two years after EPA approval of the controls determination associated with the SIP, the CEMS shall monitor and record at least the following data for each kiln (EUs: K102, K202, K302, and K402): *[AQR 12.4.3.4(a)(10)]*

    a. Exhaust gas concentration of NO_x;

    b. Diluent gas, if applicable;

    c. Exhaust gas flow rate;

    d. Hourly emissions of NO_x;

    e. Hours of CEMS operation; and

    f. Dates and hours of CEMS downtime.

5. The permittee shall conduct Relative Accuracy Test Audits (RATA) and other periodic checks of NO_x—and, if applicable, checks of diluent gas—on the CEMS at least annually, as required by 40 CFR Part 60. *[AQR 12.4.3.4(a)(10)]*

6. Effective no later than two years after EPA approval of the controls determination associated with the SIP, the permittee shall monitor each kiln (EUs: K102, K202, K302, and K402) to demonstrate compliance with the NO_x emission limit of 3.75 tons per day. Each rolling kiln's 30-operating-day average will be calculated using the following procedure: *[AQR 12.4.3.4(a)(10)]*

a. The permittee shall measure NO_x emissions from each kiln using the CEMS and sum the hourly pounds of NO_x emitted from Kilns 1, 2, 3, and 4 during the current kiln operating day and during the preceding 29 kiln operating days to obtain the total pounds of NO_x emitted for 30 kiln operating days.

b. The permittee shall divide the total pounds of NO_x by 2,000 to calculate total tons of NO_x emitted over the most recent 30 kiln operating days.

c. The permittee shall divide the total tons of NO_x by 30 to calculate the rolling 30-operating-day NO_x emission rate from all kilns.

d. The permittee shall address data during periods when the CEMS is out of control in accordance with 40 CFR Part 60, Appendix F.

7. Effective no later than two years after EPA approval of the controls determination associated with the SIP, the permittee shall monitor each kiln to demonstrate compliance with the NO_x emission limit of 3.59 lb/tlp (EUs: K102, K202, K302, and K402). Each 12-month rolling NO_x emission rate will be calculated within 30 days following the end of each calendar month using the following procedure: *[AQR 12.4.3.4(a)(10)]*

   a. The permittee shall measure NO_x emissions using the CEMS and sum the hourly pounds of NO_x emitted from each kiln for the month just completed and the 11 months preceding to calculate the total pounds of NO_X emitted over the most recent 12-month period.

   b. The permittee shall sum the total lime production, in tons, produced from Kilns 1, 2, 3, and 4 during the month just completed and the 11 months prior to calculate the total lime product produced over the most recent 12-month period. Total lime production is to consist of both saleable and any waste lime produced.

   c. The permittee shall divide the total pounds of NO_x by the total tons of lime product to calculate the 12-month rolling NO_x emission rate in lb/tlp.

   d. The permittee shall address data during periods when CEMS is out of control in accordance with 40 CFR Part 60, Appendix F.

8. Effective no later than two years after EPA approval of the controls determination associated with the SIP, the permittee shall monitor the amount of the reagent used for the SNCR for each kiln hourly. If multiple readings are taken in an hour, an hourly average may be recorded. (EUs: K102, K302, and K402). *[AQR 12.4.3.4(a)(10)]*

4.2 TESTING

~~No performance testing requirements have been identified~~.

4.3 RECORDKEEPING

1. The permittee shall keep records of all inspections, maintenance, and repairs, as required by this permit. *[AQR 12.4.3.4(a)(10)]*

2. All records, logs, etc., or copies thereof, shall be kept on-site for a minimum of five years from the date the measurement or data was entered. *[AQR 12.4.3.4(a)(10)]*

3. The permittee shall retain records of all required monitoring and performance demonstration data and supporting information for five years after the date of the sample collection, measurement, report, or analysis. Supporting information includes all records regarding calibration and maintenance of the monitoring equipment, all original strip-chart recordings for continuous monitoring instrumentation and, if applicable, all other records required to be maintained pursuant to 40 CFR Part 64.9(b). *[AQR 12.4.3.4(a)(1)]*

4. Records and data required by this permit to be maintained by the permittee may be audited at any time by a third party selected by the Control Officer. *[AQR 4.1]*

5. The permittee shall create and maintain records, all of which must be producible on-site to the Control Officer's authorized representative upon request and without prior notice during the permittee's hours of operation. *[AQR 12.4.3.4(a)(10)]*

6. The permittee shall maintain the following records on-site and include, at a minimum: *[AQR 12.4.3.4(a)(10)]*

   a. Hourly records of the amount of reagent used for the SNCR for each kiln (EUs: K102, K302, and K402);

   b. CEMS data for each kiln (EUs: K102, K202, K302, and K402); and

   c. Written procedures for the quality control program.

7. The permittee shall maintain the following records on-site that require semiannual reporting, including, at a minimum: *[AQR 12.4.3.4(a)(10)]*

   a. Daily, consecutive 30-day average of total NO_x in tpd from all kilns (EUs: K102, K202, K302, and K402);

   b. Monthly, consecutive 12-month average of total NO_x in lb/tlp from all kilns (EUs: K102, K202, K302, and K402);

   c. Magnitude and duration of excess emissions (reported as required by Section 4.4 of this permit), notifications, monitoring system performance, malfunctions, corrective actions taken, and other data required by 40 CFR Part 60; and

   d. CEMS audit results or accuracy checks, as required by 40 CFR Part 60.

4.4 REPORTING AND NOTIFICATIONS

~~1. All report submissions shall be addressed to the attention of the Control Officer. *[AQR 14.1(b)]*~~

~~2. The permittee shall provide, within a reasonable time and in writing, any information the Control Officer requests to determine whether cause exists for revising, revoking and reissuing, or terminating the permit, or to determine compliance with the conditions of the permit. Upon request, the permittee shall also furnish to the Control Officer copies of records the permit requires keeping; the permittee may furnish records deemed confidential directly to the Administrator, along with a claim of confidentiality. *[AQR 12.4.3.4(a)(7)]*~~

~~3. At the Control Officer's request, the permittee shall provide any information or analyses that will disclose the nature, extent, quantity, or degree of air contaminants that are or may be discharged by the source, and the type or nature of control equipment in use. The Control Officer may require such disclosures be certified by a professional engineer registered in the~~

~~state. In addition to this report, the Control Officer may designate an authorized agent to make an independent study and report on the nature, extent, quantity, or degree of any air contaminants that are or may be discharged from the source. An agent so designated may examine any article, machine, equipment, or other contrivance necessary to make the inspection and report. *[AQR 4.1]*~~

~~4. The permittee shall report the start of construction, construction interruptions exceeding nine months, and completion of construction to the Control Officer in writing no later than 15 working days after occurrence of the event. *[AQR 12.4.3.4(a)(12)]*~~

~~5. The permittee shall provide written notification of the actual date of commencing operation to the Control Officer within 15 calendar days. *[AQR 12.4.3.4(a)(13)]*~~

~~6. The permittee shall provide separate written notifications when commencing operations for each unit of phased construction, which may involve a series of units commencing operation at different times. *[AQR 12.4.3.4(a)(14)]*~~

7. The permittee shall submit semiannual monitoring reports to DAQ. *[AQR 12.4.3.4(a)(10)]*

8. The following requirements apply to semiannual reports: *[AQR 12.4.3.4(a)(10)]*

   a. The report shall include the items listed in Section 4.3 for semiannual reporting.

   b. The report shall be based on a calendar semiannual period, which shall include partial reporting periods.

   c. The report shall be received by DAQ within 30 calendar days after the semiannual period.

~~9. With the semiannual monitoring report, the permittee shall report to the Control Officer all deviations from permit conditions that do not result in excess emissions, including those attributable to malfunction, startup, or shutdown. Reports shall identify the probable cause of each deviation and any corrective actions or preventative measures taken. *[AQR 12.5.2.6(d)(4)(B)]*~~

~~10. Upon commencing operation of the controls required by this ATC, the permittee shall submit compliance certifications annually in writing to the Control Officer (4701 W. Russell Rd., Suite 200, Las Vegas, NV 89118) and the Region 9 Administrator (Director, Air and Radiation Division, 75 Hawthorne St., San Francisco, CA 94105). A compliance certification for each calendar year will be due on January 30 of the following year, and shall include the following: *[AQR 12.5.2.8(e)]*~~

   ~~a. The identification of each term or condition of the permit that is the basis of the certification;~~

   ~~b. The identification of the methods (or other means) used by the permittee for determining the status of compliance with each permit term and condition during the certification period. These methods and means shall include, at a minimum, the monitoring and related recordkeeping and reporting requirements described in 40 CFR Part 70.6(a)(3). If necessary, the permittee shall also identify any other material information that must be included in the certification to comply with Section 113(c)(2) of the Clean Air Act, which prohibits knowingly making a false certification or omitting material information; and~~

~~c. The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the methods or means designated in Item b above, and each deviation shall be identified and taken it into account in the compliance certification. The certification shall also identify, as possible exceptions to compliance, any periods during which compliance was required and in which an excursion or exceedance, as defined under 40 CFR Part 64, occurred.~~

~~11. The owner or operator of any source required to obtain a permit under AQR 12 shall report to the Control Officer emissions in excess of an applicable requirement or emission limit that pose a potential imminent and substantial danger to public health and safety or the environment as soon as possible, but no later than 12 hours after the deviation is discovered, and submit a written report within two days of the occurrence. *[AQR 25.6.2]*~~

~~12. Any application form, report, or compliance certification submitted to the Control Officer pursuant to the permit or the AQRs shall contain a certification by a Responsible Official, with an original signature, of truth, accuracy, and completeness. This certification, and any other required under AQR 12.5, shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. *[AQR 12.5.2.6(l)]*~~

~~13. The permittee shall submit annual emissions inventory reports based on the following: *[AQRs 18.6.1 & 12.9.2]*~~

~~a. The annual emissions inventory must be submitted to DAQ by March 31 of each calendar year (if March 31 falls on a Saturday or Sunday, or on a Nevada or federal holiday, the submittal shall be due on the next regularly scheduled business day);~~

~~b. The calculated actual annual emissions from each emission unit shall be reported even if there was no activity, along with the total calculated actual annual emissions for the source based on the emissions calculation methodology used to establish the potential to emit (PTE) in the permit or an equivalent method approved by the Control Officer prior to submittal; and~~

~~c. As the first page of text, a signed certification containing the sentence: "I certify that, based on information and belief formed after reasonable inquiry, the statements contained in this document are true, accurate, and complete." This statement shall be signed and dated by a Responsible Official of the company (a sample form is available from DAQ).~~

~~14. Stationary sources that emit 25 tons or more of NO_x and/or 25 tons or more of VOC from emission units, insignificant activities, and exempt activities during a calendar year shall submit an annual emissions statement for both pollutants. Emissions statements must include actual annual NO_x and VOC emissions from all activities, including emission units, insignificant activities, and exempt activities. Emissions statements are separate from, and additional to, the calculated annual emissions reported each year for all regulated air pollutants (i.e., the emissions inventory). *[AQR 12.9.1]*~~

15. The permittee is responsible for all applicable notification and reporting requirements contained in 40 CFR Parts 60 and 63. *[AQR 12.4.3.4(a)(10)]*

16. Regardless of the date of issuance of this ATC, the source shall comply with the schedule for report submissions outlined in Table 4-1.

Table 4-1: Required Submission Dates[1]

Required Report	Applicable Period	Due Date
Semiannual report for 1st six-month period	January, February, March, April, May, June	July 30 each year[1]
Semiannual report for 2nd six-month period and any additional annual records required	July, August, September, October, November, December	January 30 each year[1]
Annual Compliance Certification	Calendar year	January 30 each year[1]
Annual Emissions Inventory Report	Calendar year	March 31 each year[1]
Annual Emissions Statement[2]	Calendar year	March 31 each year[1]
Notification of Malfunctions, Startup, Shutdowns or Deviations with Excess Emission	As required	Within 24 hours of when permittee learns of event
Report of Malfunctions, Startup, Shutdowns or Deviations with Excess Emission	As required	Within 72 hours of DAQ notification
Deviation Report without Excess Emissions	As required	With semiannual reports[1]
Excess Emissions that Pose a Potential Imminent and Substantial Danger	As required	Within 12 hours of when permittee learns of event
Performance Testing Protocol	As required	No less than 45 days, but no more than 90 days, before anticipated test date[1]
Performance Testing	As required	Within 60 days of end of test[1]

[1]If the due date falls on a Saturday, Sunday, or federal or Nevada holiday, the submittal is due on the next regularly scheduled business day.
[2] Required only for stationary sources that emit 25 tons or more of NO_X and/or 25 tons or more of VOC during a calendar year.

~~17. The Control Officer reserves the right to require additional reporting to verify compliance with permit emission limits, applicable permit requirements, and requirements of applicable federal regulations. *[AQR 4.1]*~~

4.5 MITIGATION

~~The source has no federal offset requirements. *[AQR 12.7]*~~

5.0 *ADMINISTRATIVE REQUIREMENTS*

5.1 GENERAL

1. ~~This ATC does not modify, consolidate, supersede, and/or replace any ATC previously issued for this facility from the date of issuance of this permit forward, except for the emission units addressed in this ATC.~~

2. ~~This ATC does not supersede or replace any Part 70 requirements, including any permit conditions, compliance requirements, and/or emission limitations outlined in the Part 70 (Title V) Operating Permit.~~

3. ~~Except as provided in AQR 12.4.3.2(e) for minor revisions of a Part 70 Operating Permit, an owner or operator of an existing or new Part 70 source shall obtain an ATC Permit from the Control Officer before beginning actual construction or continuing to operate any of the following: *[AQR 12.4.1.1(a)]*~~

    a. ~~A new Part 70 source;~~

    b. ~~A "major modification," as defined in AQRs 12.2 or 12.3;~~

    c. ~~A modification that increases the Part 70 source's PTE by an amount equal to or greater than the minor NSR significant level in AQR 12.4.2.1;~~

    d. ~~Construction, modification, or reconstruction of an affected facility that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 60;~~

    e. ~~Construction or reconstruction of a new or an affected source that becomes newly subject to a standard, limitation, or other requirement under 40 CFR Part 63, including, but not limited to, construction or modification that requires preconstruction review under 40 CFR Part 63.5; or~~

    f. ~~A modification to a solid waste incinerator unit, as defined by an applicable standard under 40 CFR Part 60.~~

4. ~~Unless the Control Officer receives and grants a written request to extend the 18-month period referenced in AQR 12.4.1.1(b)(1) or (b)(2) at least 30 days before the deadline, an ATC Permit issued under AQR 12.4 or an ATC authorization issued under AQR 12.5 shall remain in effect only if: *[AQR 12.4.1.1(b)]*~~

    a. ~~The owner or operator commences the construction, modification, or reconstruction of the Part 70 source within 18 months of the issuance date of an ATC Permit or authorization to construct;~~

    b. ~~Such activity is not discontinued for a period greater than 18 months; and~~

    c. ~~The Control Officer does not revoke and reissue, or terminate, the ATC Permit for cause.~~

5. ~~If an existing Part 70 Operating Permit would prohibit construction, modification, or reconstruction, the owner or operator of the Part 70 source must obtain a Part 70 Operating Permit revision pursuant to AQRs 12.5.2.13 or 12.5.2.14, as appropriate, before commencing operation.~~ ~~*[AQR 12.4.1.1(c)]*~~

6. ~~Upon presentation of credentials, the permittee shall allow the Control Officer (or any authorized representative) to enter the premises where the source is located or emissions-related activity is conducted and to:~~ ~~*[AQR 12.4.3.4(a)(8)]*~~

   a. ~~Access and copy, during normal business hours, any records that must be kept under the conditions of the permit;~~

   b. ~~Inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this ATC;~~

   c. ~~Sample or monitor substances or parameters to assure compliance with the conditions of this ATC or applicable requirements; and~~

   d. ~~Document alleged violations using such devices as cameras or video equipment.~~

7. ~~This ATC does not convey any property rights or exclusive privilege.~~ ~~*[AQR 12.4.3.4(a)(6)]*~~

8. ~~The permittee shall post this ATC in a location clearly visible and accessible to facility employees and department representatives.~~ ~~*[AQRs 12.4.3.4(a)(16) & 12.13]*~~

9. ~~The permittee shall pay all fees assessed pursuant to AQR 18.~~ ~~*[AQR 12.4.3.4(a)(17)]*~~

10. ~~A timely application for a source applying for a Part 70 Operating Permit for the first time is one that is submitted within 12 months of the source becoming subject to the permit program. If a source submits a timely application under this provision, it may continue operating under its ATC Permit until final action is taken on its application for a new Part 70 Operating Permit.~~ ~~*[AQR 12.5.2.1(a)(1)]*~~

11. ~~A timely application for an existing Part 70 source that has obtained an ATC Permit is one that is submitted within 12 months of the source commencing operation of the modification or reconstruction authorized by this ATC, or on or before an earlier date that the Control Officer may establish. However, where an existing Part 70 Operating Permit would prohibit such construction or change in operation, the source must obtain a Part 70 permit revision pursuant to AQR 12.5.2.14 before commencing operation.~~ ~~*[AQR 12.5.2.1(a)(3)]*~~

5.2 MODIFICATION, REVISION, AND RENEWAL REQUIREMENTS

1. ~~The Control Officer may revise an ATC Permit only through:~~ ~~*[AQRs 12.4.4.1(a)]*~~

   a. ~~An administrative or significant permit revision, as specified in Items b and c below;~~

   b. ~~The Part 70 Operating Permit procedures specified in AQR 12.5.2.14; or~~

~~c. A revision of AQR 12.4-applicable requirements in a Part 70 Operating Permit using the procedures in AQRs 12.5.2.13 or 12.4.2.14. Revising the applicable requirements of, or adding terms and conditions to, the Part 70 Operating Permit may supersede or append certain terms and conditions to the ATC Permit, as specified in AQR 12.4.5.2(a).~~

~~2. The permittee shall file an application to make any change in the ownership or Responsible Official of the source, and may implement the change immediately upon submittal of the request provided the current and new permittee have submitted to the Control Officer a written agreement with a specific date for transfer of permit responsibility, coverage, and liability, and that the permit transfer procedures in AQR 12.12 are complied with. *[AQRs 12.4.4.1(b)(1)(D)]*~~

~~3. The permittee shall file an application for a transfer of ownership at least 30 days before the date of a change in ownership or operational control of the source. This application shall constitute a temporary ATC under the conditions of the existing permit. *[AQRs 12.12.2(c) & (d)]*~~

~~4. The Control Officer may revise, revoke and reissue, reopen and revise, or terminate this ATC for cause. *[AQR 12.4.3.4(a)(5)]*~~

5.3 COMPLIANCE REQUIREMENTS

~~1. Each of the conditions and requirements of this ATC is severable. If any are held invalid, the remaining conditions and requirements shall continue in effect. *[AQR 12.4.3.4(a)(2)]*~~

~~2. The permittee shall comply with all conditions contained in this ATC. Any noncompliance constitutes a violation and is grounds for an action for noncompliance, revocation and reissuance, or termination of the permit by the Control Officer, or for reopening or revising of the permit by the permittee as directed by the Control Officer. *[AQR 12.4.3.4(a)(3)]*~~

~~3. The need to halt or reduce activity to maintain compliance with the conditions of this ATC is not a defense to noncompliance with any condition of this ATC. *[AQR 12.4.3.4(a)(4)]*~~

~~4. Upon commencement of operations, the permittee shall report to the Control Officer any upset, breakdown, malfunction, emergency, or deviation that causes emissions of regulated air pollutants in excess of any limits set by regulations or by this ATC. The report shall be in two parts, as specified below: *[AQR 25.6.1]*~~

~~a. Within 24 hours of the time the permittee learns of the excess emissions, the permittee shall notify DAQ by phone at (702) 455-5942, by fax at (702) 383-9994, or by email at AQCompliance@clarkcountynv.gov.~~

~~b. Within 72 hours of the notification required by Item a above, the permittee shall submit a detailed written report containing the information required by AQR 25.6.3.~~

~~5. The permittee shall report to the Control Officer all deviations from permit conditions that do not result in excess emissions, including those attributable to malfunction, startup, or shutdown, with the semiannual monitoring report. Reports shall identify the probable cause of each deviation and any corrective actions or preventative measures taken. *[AQR 12.5.2.6(d)(4)(B)(iii)]*~~

~~6. A Responsible Official of the source shall certify that, based on information and belief formed after reasonable inquiry, the statements made in any document required to be submitted by any condition of this ATC are true, accurate, and complete. *[AQR 12.4.3.4(a)(9)]*~~

Appendix A.2 - Tracy Generating Station, NV Energy

Provisions provided in the following air quality operating permit issued by the Nevada Division of Environmental Protection for the Tracy Generating Station are hereby incorporated and adopted into Nevada's Second Regional Haze SIP by reference. In this appendix, NDEP is only providing pages containing specific permit conditions relevant to this Regional Haze SIP. Provisions that are ~~struck-out~~ are not intended to be incorporated into the SIP by reference for approval or intended to be codified as part of Nevada's Second Regional Haze SIP.

NEVADA DIVISION OF
ENVIRONMENTAL PROTECTION

STATE OF NEVADA
Department of Conservation & Natural Resources
Steve Sisolak, Governor
Bradley Crowell, Director
Greg Lovato, Administrator

March 23, 2022

Jason Hammons
Senior Director, Generation
Sierra Pacific Power Company d/b/a NV Energy
6226 West Sahara Avenue, M/S 78
Las Vegas, Nevada 89146

RE: Notification of Issuance of the Renewal, Minor Revisions, Reopen-Revision of Class I Air Quality Operating Permit AP4911-0194.04, FIN A0029, Air Cases 9674, 10135, 10818, 11106 – Tracy Power Generating Station

Dear Mr. Hammons:

The Nevada Division of Environmental Protection – Bureau of Air Pollution Control (BAPC) has reviewed the applications submitted by Sierra Pacific Power Company d/b/a NV Energy – Tracy Power Generating Station (NV Energy) on May 18, 2018, July 2, 2019, and May 7, 2021, respectively, for the above-referenced operating permit under legal authority from Nevada Revised Statutes (NRS) 445B.100 through 445B.640, inclusive, and pursuant to regulations in Nevada Administrative Code (NAC) 445B.001 through 445B.3689, inclusive. Based upon technical review and recommendation, I hereby issue the operating permit with appropriate restrictions. Enclosed is your copy of the operating permit which must be posted conspicuously at the facility.

Pursuant to NAC 445B.3395, a 30-day public comment period was initiated and a draft copy of the operating permit was published for public review on January 31, 2022. The public comment period ended on March 2, 2022. The BAPC did not receive comments. The draft copy of the above-referenced permit was submitted to EPA Region 9 on January 31, 2022 for the required 45-day review period pursuant to NAC 445B.3395 which defaults to end on March 17, 2022. EPA Region 9 had no further comments.

In accordance with NRS 445B.340 and NAC 445B.890, you may appeal the Department's issuance of the operating permit within 10 days after you receive the operating permit. Appeals may be filed with the State Environmental Commission located at 901 S. Stewart Street, Carson City, Nevada 89701. For questions regarding appeals, call (775) 687-9374. Please review the operating permit carefully and ensure you understand all conditions, restrictions, monitoring, recordkeeping, and other requirements. If you have any questions, contact Mark Talavera at (775) 687-9470 or mtalavera@ndep.nv.gov.

Sincerely,

Jennifer Schumacher, E.I., C.P.M.
Chief, Bureau of Air Pollution Control

JS/JM/mt

Enclosure:	Class I Air Quality Operating Permit AP4911-0194.04
Certified Mail No.	9171 9690 0935 0218 7438 26
E-Copy:	Starla Lacy, NV Energy
	Tony Garcia, NV Energy
	Christopher Heintz, NV Energy
	Dawn Clevenger, NV Energy
	Brigid McHale, NV Energy
	Sean Spitzer, NV Energy

Nevada Department of Conservation and Natural Resources • Division of Environmental Protection
Bureau of Air Pollution Control
901 SOUTH STEWART STREET SUITE 4001
CARSON CITY, NEVADA 89701-5249
p: 775-687-9349 • www.ndep.nv.gov/bapc

Facility ID No. A0029 *Permit No.* AP4911-0194.04

CLASS I AIR QUALITY OPERATING PERMIT (*40 CFR Part 70 Program)*

Issued to: SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY – TRACY POWER GENERATING STATION (HEREINAFTER REFERRED TO AS PERMITTEE)
Mailing Address: P.O. BOX 98910, M/S 25, LAS VEGAS, NEVADA 89151
Physical Address: 1799 WALTHAM WAY, SPARKS, NEVADA 89437
Driving Directions: 17 MILES EAST OF SPARKS, NV TAKE THE USA PARKWAY EXIT SOUTH OFF INTERSTATE 80. TURN WEST ON WALTHAM WAY FOR APPROXIMATELY 1.5 MILES
General Facility Location:

SECTION 28, T 20 N, R 22 E, MDB&M
SECTION 29, T 20 N, R 22 E, MDB&M
SECTION 32, T 20 N, R 22 E, MDB&M
SECTION 33, T 20 N, R 22 E, MDB&M
HA 83 – TRACY SEGMENT / STOREY COUNTY
NORTH 4,382,107 M, EAST 283,338 M, UTM ZONE 11, NAD 83

Emission Unit List:

A. System 03A – Tracy Unit #3 Steam Boiler

S2.003	Steam Boiler (Manufactured by Babcock & Wilcox; Model B&W; Serial 3474; Date Aug 1970; Maximum Heat Input 1,150 MMBtu/hr; Nominal Output 113 MW)

B. System 05A – Clark Mountain Combustion Turbine #3 – Primary Operating Scenario

S2.006	Simple Cycle Combustion Turbine (Manufactured by General Electric; Model PG 7111 (EA); Serial 813E494H3; Date 1992; Maximum Heat Input 1,011.2 MMBtu/hr; Output 83.5 MW)

~~**C. System 05C – Clark Mountain Combustion Turbine Unit #3 – Power Augmented Scenario**~~

~~S2.006~~	~~Simple Cycle Combustion Turbine (Manufactured by General Electric; Model PG 7111 (EA); Serial 813E494H3; Date 1992; Maximum Heat Input 1,011.2 MMBtu/hr; Output 83.5 MW)~~

D. System 06A – Clark Mountain Combustion Turbine Unit #4 – Primary Operating Scenario

S2.007	Simple Cycle Combustion Turbine (Manufactured by General Electric; Model PG 7111 (EA); Serial 943E972H6; Date 1992; Maximum Heat Input 1,011.2 MMBtu/hr; Output 83.5 MW)

~~**E. System 06C – Clark Mountain Combustion Turbine #4 – Power Augmented Scenario**~~

~~S2.007~~	~~Simple Cycle Combustion Turbine (Manufactured by General Electric; Model PG 7111 (EA); Serial 943E972H6; Date 1992; Maximum Heat Input 1,011.2 MMBtu/hr; Output 83.5 MW)~~

F. System 07C – Tracy Unit #4 Piñon Pine Combustion Turbine/Duct Burner – Pipeline Quality Natural Gas

S2.009	Combustion Turbine/HRSG (Manufactured by General Electric; Model MS6001FA; Serial 1646; Maximum Heat Input 763.9 MMBut/hr; Nominal Output 107 MW)
S2.009.1	Duct Burner (Manufactured by Forney; Maximum Heat Input 156.464 MMBtu/hr; Nominal Output 23 MW)

~~**G. System 25 – Tracy Unit #3 Cooling Tower System**~~

~~S2.053~~	~~Tracy Unit #3 Cooling Tower (P026) (Positive Draft Type; Marley Model 6515-04-03; Serial 445TS; 70,000 gal/min Circulating Water Flow Rate)~~

Issued to: SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY – TRACY GENERATING STATION (AS PERMITTEE)

Emission Unit List (Continued):

~~**H. System 26 – Piñon Pine Unit #4 Cooling Tower System**~~

~~S2.054~~ ~~Piñon Pine #4 Cooling Tower (P027) (Positive Draft Type; Manufactured by Marley; Model W467-4.0-3; Serial 73346-W467-95; 40,000 gal/min Circulating Water Flow Rate)~~

~~**I. System 28 – Diesel Fuel Storage Tank System #1**~~

~~S2.056~~ ~~Diesel Fuel Storage Tank System #1 (No. 2 Distillate Fuel Oil; Manufactured by Chicago Bridge & Iron Company; Model Horton Tank; 1,050,000 Gallon Capacity)~~

~~**J. System 29 – Diesel Fuel Storage Tank System #2**~~

~~S2.057~~ ~~Diesel Storage Tank #2 (No. 2 Distillate Fuel Oil; Manufactured by Pitt-Des Moines Inc.; 60,000 Gallon Capacity)~~

~~**K. System 31 – Gasoline Dispensing Facility**~~

~~S2.063~~ ~~Gasoline Storage Tank #2 (Manufactured by ConVault; Model RN 500 3SF; 1,000 Gallon Capacity)~~

L. System 32 – Combined Cycle Combustion Turbine Circuit No. 8 – Pipeline Quality Natural Gas – 254 MW Nominal Output

S2.064 Combined Cycle Combustion Turbine #8 (Manufactured by General Electric; Serial CT8-298613; Date 2007; Maximum Heat Input Rate 1,862.0 MMBtu/hr)

S2.065 Duct Burner #8 (Manufactured by Nooter; Serial DB-22896A; Date 2007; Maximum Heat Input Rate 660.0 MMBtu/hr) & Heat Recovery Steam Generator #8 (Manufactured by General Electric; Serial HRSG8-CP28-08-01; Date 2007)

M. System 33 – Combined Cycle Combustion Turbine Circuit No. 9 – Pipeline Quality Natural Gas – 254 MW Nominal Output

S2.066 Combined Cycle Combustion Turbine #9 (Manufactured by General Electric; Serial CT9-298614; Date 2007; Maximum Heat Input Rate 1,862.0 MMBtu/hr)

S2.067 Duct Burner #9 (Manufactured by Nooter; Seral DB-22896B; Date 2007; Maximum Heat Input Rate 660.0 MMBtu/hr) & Heat Recovery Steam Generator #9 (Manufactured by General Electric by General Electric; Serial HRSG9-CP28-09-01; Date 2007)

~~**N. System 34 – Natural Gas Fired Auxiliary Boiler**~~

~~S2.068~~ ~~Auxiliary Boiler (Manufactured by Superior Boiler Works, Inc.; Model 4-X-4502-S150-ICCF-G; Serial 16151; Date 2007; Maximum Heat Input Rate 42.0 MMBtu/hr)~~

~~**O. System 35 – Emergency Diesel Generator for Combustion Turbine No. 8 and 9**~~

~~S2.069~~ ~~Emergency Diesel Generator (Manufactured by Cummins Power Generation; Model DQGAA-5791509; Serial C070032064; Date 2007; Maximum Heat Input Rate 12.7 MMBtu/hr; 1,848 hp)~~

~~**P. System 36 – Emergency Diesel Generator for Switchyard**~~

~~S2.070~~ ~~Emergency Diesel Generator (Manufactured by Cummins Power Generation; Model DSHAE-5867669; Serial F070074477; Date 2007; Maximum Heat Input Rate 1.56 MMBtu/hr; 148 HP)~~

~~**Q. System 40 – Emergency Diesel Generator for Boiler No. 3**~~

~~S2.074~~ ~~Emergency Diesel Generator (Manufactured by Detroit Allison Diesel; Model 10437305; Serial 4A0189756; Date 1974; Maximum Heat Input Rate 1.07 MMBtu/hr; 117 hp)~~

Section IV. Specific Operating Conditions (continued)

B. Emission Unit S2.006

System 05A – Clark Mountain Combustion Turbine Unit #3 – Primary Operating Scenario		Location UTM (Zone 11, NAD 83)	
		m North	m East
S2.006	Simple Cycle Combustion Turbine (Manufactured by General Electric; Model PG 7111 (EA); Serial 813E494H3; Date 1992; Maximum Heat Input 1,011.2 MMBtu/hr; Output 83.5 MW)	4,382,280	283,384

1. Air Pollution Control Equipment (NAC 445B.3405)
   a. Emissions from **S2.006** shall be controlled by **Dry Low NO_X Burners** while combusting natural gas only. Emissions from **S2.006** shall be controlled with **Water Injection** while combusting No. 2 Distillate Fuel Oil under "Emergency" conditions defined in **B.2.c.** of this section. Note, these controls are not add-on controls.
   ~~b. Descriptive Stack Parameters~~
   ~~Stack Height: 55 feet~~
   ~~Stack Dimensions: 9.5 x 18.33 feet~~
   ~~Stack Temperature: 1,000 °F~~

~~2. Operating Parameters (NAC 445B.3405)~~
   ~~a. **S2.006** may consume only **Pipeline Quality Natural Gas** when operating under this scenario, except during emergency conditions as defined in **B.2.c.** of this section.~~
   ~~b. The maximum allowable heat input rate for **S2.006** shall not exceed **1,011.2 million Btu (MMBtu)** per any one-hour period.~~
   ~~c. "Emergency" conditions are defined as "unexpected loss of electric system generation due to:~~
      ~~(1) Curtailment or unavailability of gas for purchase where the results would be the curtailment of services to customers; and/or~~
      ~~(2) Upset/malfunction of natural gas s0uppliers pipeline or equipment necessary to fire the combustion turbines on natural gas."~~
   ~~The Permittee shall notify the Bureau of Air Pollution Control within 24 hours of operation when combusting **No. 2 Distillate Fuel Oil** during an emergency condition. A report shall be submitted within 30 days of the emergency operation, which provides justification for the combustion of **No. 2 Distillate Fuel Oil** and the extent of the operation for consideration as an emergency period.~~
   ~~d. Hours~~
      ~~(1) **S2.006** may operate a total of **24** hours per day.~~
      ~~(2) **S2.006** may not combust **No. 2 Distillate Fuel** Oil in excess of **500** hours per calendar year, under any conditions.~~

3. Emission Limits (NAC 445B.305, NAC 445B.3405)
   The Permittee, upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from **S2.006** the following pollutants in excess of the following specified limits:
   ~~a. The discharge of **PM** (particulate matter) to the atmosphere shall not exceed **7.20** pounds per hour, nor more than **31.5** tons per 12-month rolling period.~~
   ~~b. The discharge of PM_{10} (particulate matter less than or equal to 10 microns in diameter) to the atmosphere shall not exceed **7.2** pounds per hour, nor more than **31.54** tons per 12-month rolling period.~~
   ~~c. NAC 445B.2203 – The maximum allowable discharge of PM_{10} to the atmosphere from **S2.006** shall not exceed **0.21** pounds per MMBtu.~~
   ~~d. The discharge of $PM_{2.5}$ (particulate matter less than or equal to 2.5 microns in diameter) to the atmosphere shall not exceed **7.2** pounds per hour, nor more than **31.54** tons per 12-month rolling period.~~
   ~~e. The discharge of SO_2 (sulfur dioxide) to the atmosphere shall not exceed **0.55** pound per hour, nor more than **2.01** tons per 12-month rolling period.~~

Section IV. Specific Operating Conditions (continued)

B. Emission Unit S2.006 (continued)

3. Emission Limits (NAC 445B.305, NAC 445B.3405) (continued)
The Permittee, upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from **S2.006** the following pollutants in excess of the following specified limits:
   f. The discharge of **NOx** (oxides of nitrogen) to the atmosphere shall not exceed:
      (1) **9** parts per million by volume (ppmv) at 15 percent oxygen and on a dry basis, based on a 24-hour rolling period;
      (2) **42.0** pounds per hour, based on a 720-hour rolling period;
      (3) **122.64** tons per year, based on a 12-month rolling period.
   ~~g. The discharge of **CO** (carbon monoxide) to the atmosphere shall not exceed:~~
      ~~(1) **25** ppmv, based on a 24-hour rolling period.~~
      ~~(2) **54.0** pounds per hour, based on a 720-hour rolling period.~~
      ~~(2) **115.0** pounds per hour, based on a 60-minute block average.~~
      ~~(3) **205.86** tons per 12-month rolling period.~~
   ~~h. The discharge of **VOCs** (volatile organic compounds) to the atmosphere shall not exceed **4.25** pounds per hour, nor more than **18.6** tons per 12-month rolling period.~~
   ~~i. NAC 445B.22017 – The opacity from the **S2.006** shall not equal or exceed **20** percent.~~

~~4. Specific Acid Rain Requirements (NAC 445B.305, 40 CFR 72.9, 40 CFR 73.10(b)(2))~~
   ~~a. The Permittee shall not exceed the SO_2 emission levels (acid rain allowances) for the indicated years as shown in Table B-1 below without holding the required acid rain allowances in accordance with Section **I.Y.2.** of this Operating Permit and pursuant to 40 CFR Part 72.9, and specified in Table 2 of 40 CFR Part 73.10(b)(2):~~

~~**Table B-1: Acid Rain Allowance Allocations**~~						
~~**S2.006**~~	~~**Phase II (Years 2010 and Beyond) Utility Boilers > 25 MW Output Capacity**~~	~~**2015**~~	~~**2018**~~	~~**2019**~~	~~**2020**~~	~~**2021**~~
		~~*0*~~	~~*0*~~	~~*0*~~	~~*0*~~	~~*0*~~

   ~~b. The Permittee shall comply with the "Standard Requirements" provisions of the SO_2 acid rain permit application dated **December 12, 2013** entitled "Acid Rain Permit Application – For Acid Rain Permit Renewal" and all references contained therein, as submitted with the Permittee's application for renewal of Class I Air Quality Operating Permit.~~

~~5. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405)~~
~~The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.~~
   ~~a. Monitor and record the hours of operation for **S2.006** on a daily basis.~~
   ~~b. Calibrate, operate, and maintain a fuel flow meter to continuously measure the volume of **Pipeline Quality Natural Gas** consumed in **S2.006** (in standard cubic feet or hundreds of standard cubic feet). The fuel flow meter shall be installed at an appropriate location in the fuel delivery system to accurately and continuously measure the fuel consumed in **S2.006** in accordance with the requirements prescribed in 40 CFR Part 75.~~
   ~~c. Install, calibrate, operate, and maintain a Continuous Data Collection System (CDCS) to continuously record the quantity (in standard cubic feet or hundreds of standard cubic feet) of **Pipeline Quality Natural Gas** as measured by the fuel flow meter required under **B.5.b.** of this section. The CDCS will be installed, calibrated, operated and maintained in accordance with the manufacturer's specifications and requirements prescribed in 40 CFR Part 75.~~

Section IV. Specific Operating Conditions (continued)

B. Emission Unit S2.006 (continued)

5. ~~Monitoring, Recordkeeping, and Reporting (NAC 445B.3405) (continued)~~
~~The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record.~~
   ~~d. Determine the gross calorific value (GCV) of **Pipeline Quality Natural Gas** consumed in **S2.006** by sampling the **Pipeline Quality Natural Gas** in **S2.006** on a monthly basis. The GCV of the gas sample shall be determined using one of the following methods: ASTM D1826-94; ASTM D3588-98; ASTM D4891-89; Gas Processors Association (GPA) Standard 2172-96; Calculation of Gross Heating Value; Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis; or GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography. Alternatively, at least once each month, the GCV may be verified by the contractual supplier, or the Permittee may use a maximum GCV value of 1,060 Btu/scf. If the supplier certification is used to verify the GCV, the supplier must provide documentation identifying the test method(s) used to determine the GCV.~~
   ~~e. Missing GCV or fuel flow data may be substituted as prescribed in 40 CFR Part 75, Appendix D.~~
   ~~f. The hourly heat input of the **Pipeline Quality Natural Gas** (in MMBtu/hr) combusted will be calculated from the hourly fuel usage recorded in **B.5.c.** of this section.~~

~~**Sample Calculation:**~~

~~**(scf Natural Gas/hr)(Btu/scf) = Btu/hr or MMBtu/hr**~~

   ~~g. The hourly emission rate of PM, PM_{10}, $PM_{2.5}$, CO, and VOC, each, in pounds per hour (lbs/hr) will be calculated from the hourly quantity of **Pipeline Quality Natural Gas** combusted determined in **B.5.c.** of this section, and the emission factor derived in **B.6.l.** of this section.~~

~~**Sample Calculation:**~~

~~**(scf/hr)(lbs pollutant/scf) = lbs pollutant/hr**~~

~~**or**~~

~~**(MMBtu/hr)(lbs pollutant/MMBtu) = lbs pollutant/hr**~~

   ~~h. The hourly emission rate of PM, PM_{10}, $PM_{2.5}$, CO, and VOC, each in pounds per MMBtu (lbs/MMbtu) will be calculated from the heat content of the fuel determined in **B.5.d.** of this section, and the emission factor derived in **B.6.l.** of this section.~~

~~**Sample Calculation:**~~

~~**(scf/Btu)(lb pollutant/scf) = lbs pollutant/Btu or lbs pollutant/MMBtu**~~

   ~~i. Calculate annually the SO_2 emissions in tons based on quantity of **Pipeline Quality Natural Gas** determined in **B.5.c.** of this section and sulfur in units of grains per dry standard cubic feet of **Pipeline Quality Natural Gas** from the SO_2 emission factor for **Pipeline Quality Natural Gas** combusted from 40 CFR Part 75 Appendix D.~~

Section IV. Specific Operating Conditions (continued)

B. Emission Unit S2.006 (continued)

6. ~~Performance and Compliance Testing (NAC 445B.3405, (NAC 445B.252(1))~~
~~The Permittee, upon issuance of this operating permit, shall conduct and record renewal performance testing at least 90 days prior to the expiration of this operating permit, but no earlier than 365 days from the date of expiration of this operating permit, and every 5 years thereafter, in accordance with the following:~~
   a. ~~All opacity compliance demonstrations and performance tests must comply with the advance notification, protocol review, operational conditions, reporting, and other requirements of Section **I.I.**, Testing and Sampling (NAC 445B.252), of this operating permit. Material sampling must be conducted in accordance with protocols approved by the Director. All performance test results shall be based on the arithmetic average of three valid runs. (NAC 445B.252(5))~~
   b. ~~Testing shall be conducted on the exhaust stack of **S2.006**.~~
   c. ~~Method 5 in Appendix A of 40 CFR Part 60 shall be used to determine PM emissions. The sample volume for each test run shall be at least 1.7 dscm (60 dscf). Test runs must be conducted for up to two hours in an effort to collect this minimum sample.~~
   d. ~~Method 201A and Method 202 in Appendix M of 40 CFR Part 51 shall be used to determine PM_{10} and $PM_{2.5}$ emissions. The sample time and sample volume collected for each test run shall be sufficient to collect enough mass to weigh accurately.~~
   e. ~~The Method 201A and 202 test required in this section may be replaced by a Method 5 in Appendix A of 40 CFR Part 60 and Method 202 in Appendix M of 40 CFR Part 51 test. All particulate captured in the Method 5 and Method 202 test performed under this provision shall be considered $PM_{2.5}$ for determination of compliance.~~
   f. ~~Method 7E in Appendix A of 40 CFR Part 60 shall be used to determine the nitrogen oxides concentration. Each test will be run for a minimum of one hour.~~
   g. ~~Method 9 in Appendix A of 40 CFR Part 60 shall be used to determine opacity. Opacity observations shall be conducted concurrently with the applicable performance test. The minimum total time of observations shall be six minutes (24 consecutive observations recorded at 15-second intervals), unless otherwise specified by an applicable subpart.~~
   h. ~~Method 10 in Appendix A of 40 CFR Part 60 shall be used to determine the carbon monoxide concentration. Each test will be run for a minimum of one hour.~~
   i. ~~Method 25A in Appendix A of 40 CFR Part 60 shall be used to determine the volatile organic compound concentration. Method 18 in Appendix A of 40 CFR Part 60 or Method 320 in Appendix A of CFR Part 63 may be used in conjunction with Method 25A to break out the organic compounds that are not considered VOC's by definition per 40 CFR 51.100(s). Each Method 25A test will be run for a minimum of one hour.~~
   j. ~~The performance tests required in **B.6.c.** through **B.6.i.** of this section shall be conducted at the best achievable heat input rate at normal operating conditions, unless otherwise approved pursuant to NAC 445B.252. Should any anticipated major boiler overhaul(s) be scheduled to be performed, which coincide with the performance tests, the performance testing shall be performed prior to the overhaul(s). If the performance testing cannot be performed prior to a major boiler overhaul(s), the performance testing shall be performed as soon as practicable following the overhaul(s), but not earlier than 60 days following the overhaul(s).~~
   k. ~~The Permittee shall record the quantity of **Pipeline Quality Natural Gas** combusted (in standard cubic feet or hundreds of standard cubic feet) for each test run and the heat content (in Btu/scf) for each performance test event.~~

Section IV. Specific Operating Conditions (continued)

B. Emission Unit S2.006 (continued)

6. ~~Performance and Compliance Testing (NAC 445B.3405, (NAC 445B.252(1)) (continued)~~
~~The Permittee, upon issuance of this operating permit, shall conduct and record renewal performance testing at least 90 days prior to the expiration of this operating permit, but no earlier than 365 days from the date of expiration of this operating permit, and every 5 years thereafter, in accordance with the following:~~
~~l. Using the most recent performance tests, as specified above, the Permittee shall calculate the following emission factors, based on the average of 3 test runs:~~
   ~~(1) Pounds of PM per scf (lbs PM/scf) of Pipeline Quality Natural Gas, or pounds of PM per MMBtu (lbs PM/MMBtu) of Pipeline Quality Natural Gas.~~
   ~~(2) Pounds of PM_{10} per scf (lbs PM_{10}/scf) of Pipeline Quality Natural Gas, or pounds of PM_{10} per MMBtu (lbs PM_{10}/MMBtu) of Pipeline Quality Natural Gas.~~
   ~~(3) Pounds of $PM_{2.5}$ per scf (lbs $PM_{2.5}$/scf) of Pipeline Quality Natural Gas, or pounds of $PM_{2.5}$ per MMBtu (lbs PM_{10}/MMBtu) of Pipeline Quality Natural Gas.~~
   ~~(4) Pounds of NO_X per scf (lbs NO_X/scf) of Pipeline Quality Natural Gas, or pounds of NO_X per MMBtu (lbs NO_X/MMBtu) of Pipeline Quality Natural Gas.~~
   ~~(5) Pounds of CO per scf (lbs CO/scf) of Pipeline Quality Natural Gas, or pounds of CO per MMBtu (lbs CO/MMBtu) of Pipeline Quality Natural Gas.~~
   ~~(6) Pounds of VOC per scf (lbs VOC/scf) of Pipeline Quality Natural Gas, or pounds of VOC per MMBtu (lbs VOC/MMBtu) of Pipeline Quality Natural Gas.~~

7. ~~Federal Requirements~~
~~a. Standards of Performance for New Stationary Sources – 40 CFR Part 60 Subpart GG – Standards of Performance for Stationary Gas Turbines~~
   ~~(1) Standards for Nitrogen Oxides (40 CFR 60.332)~~
   ~~On and after the date on which the performance test required by 40 CFR Part 60.8 is completed, the Permittee shall not discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxide in excess of **85.0** parts per million by volume (ppmv) corrected to 15 percent oxygen. (40 CFR 60.332(a)(1))~~
   ~~(2) Standard for Sulfur Dioxide (40 CFR 60.333)~~
   ~~On and after the date on which the performance test required to be conducted by 40 CFR Part 60.8 is completed, the Permittee shall comply with one or the other of the following conditions:~~
      ~~(a) The Permittee shall not cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of **0.0015** percent by volume at 15 percent oxygen on a dry basis. (40 CFR 60.333(a))~~
      ~~(b) The Permittee shall not burn in any stationary gas turbine any fuel which contains total sulfur in excess of **0.8** percent by weight (8,000 ppmw). (40 CFR 60.333(b))~~
   ~~(3) Monitoring of Operations (40 CFR 60.334)~~
      ~~(a) Except as provided in 40 CFR Part 60.334(b), the Permittee shall install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine while combusting No. 2 Distillate Fuel Oil under "Emergency" conditions defined in **B.2.c.** of this section. (40 CFR 60.334(a))~~
      ~~(b) The Permittee may, as an alternative to operating the continuous monitoring system described in 40 CFR Part 60.334(a), install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F-14a or F-14b in Appendix F to 40 CFR Part 75 and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained as stated in 40 CFR Parts 60.334(b)(1) through 60.334(b)(3). (40 CFR 60.334(b))~~

Section IV. Specific Operating Conditions (continued)

D. Emission Unit S2.007

System 06A – Clark Mountain Combustion Turbine Unit #4 – Primary Operating Scenario		Location UTM (Zone 11, NAD 83)	
		m North	m East
S2.007	Simple Cycle Combustion Turbine (Manufactured by General Electric; Model PG 7111 (EA); Serial 943E972H6; Date 1992; Maximum Heat Input 1,011.2 MMBtu/hr; Output 83.5 MW)	4,382,268	283,329

1. Air Pollution Control Equipment (NAC 445B.3405)
   a. Emissions from **S2.007** shall be controlled by **Dry Low NO_X Burners** while combusting Pipeline Natural Gas only. Emissions from **S2.006** shall be controlled with **Water Injection** while combusting No. 2 Distillate Fuel Oil under "Emergency" conditions defied in **D.2.c.** of this section. Note, these controls are not add-on controls.
   ~~b. Descriptive Stack Parameters~~
   ~~Stack Height: 55.0 feet~~
   ~~Stack Dimensions: 9.5 x 18.33 feet~~
   ~~Stack Temperature: 1,000 °F~~

~~2. Operating Parameters (NAC 445B.3405)~~
   ~~a. **S2.007** may consume only **Pipeline Quality Natural Gas** when operating under this scenario, except during emergency conditions as defined in **D.2.c.** of this section.~~
   ~~b. The maximum allowable heat input rate for **S2.007** shall not exceed **1,011.2 million Btu (MMBtu)** per any one-hour period.~~
   ~~c. "Emergency" conditions are defined as "unexpected loss of electric system generation due to:~~
      ~~(1) Curtailment or unavailability of gas for purchase where the results would be the curtailment of services to customers; and/or~~
      ~~(2) Upset/malfunction of natural gas suppliers pipeline or equipment necessary to fire the combustion turbines on natural gas."~~
   ~~The Permittee shall notify the Bureau of Air Pollution Control within 24 hours of operation when combusting **No. 2 Distillate Fuel Oil** during an emergency condition. A report shall be submitted within 30 days of the emergency operation, which provides justification for the combustion of **No. 2 Distillate Fuel Oil** and the extent of the operation for consideration as an emergency period.~~
   ~~d. Hours~~
      ~~(1) **S2.007** may operate a total of **24** hours per day.~~
      ~~(2) **S2.007** may not combust **No. 2 Distillate Fuel** Oil in excess of **500** hours per calendar year, under any conditions.~~

3. Emission Limits (NAC 445B.305, NAC 445B.3405)
   The Permittee, upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from **S2.007** the following pollutants in excess of the following specified limits:
   ~~a. The discharge of **PM** (particulate matter) to the atmosphere shall not exceed **7.20** pounds per hour, nor more than **31.54** tons per 12-month rolling period.~~
   ~~b. The discharge of **PM_{10}** (particulate matter less than or equal to 10 microns in diameter) to the atmosphere shall not exceed **7.2** pounds per hour, nor more than **31.54** tons per 12-month rolling period.~~
   ~~c. NAC 445B.2203 – The maximum allowable discharge of **PM_{10}** to the atmosphere from **S2.007** shall not exceed **0.21** pounds per MMBtu.~~
   ~~d. The discharge of **$PM_{2.5}$** (particulate matter less than or equal to 2.5 microns in diameter) to the atmosphere shall not exceed **7.2** pounds per hour, nor more than **31.54** tons per 12-month rolling period.~~
   ~~e. The discharge of **SO_2** (sulfur dioxide) to the atmosphere shall not exceed **0.55** pound per hour, nor more than **2.01** tons per 12-month rolling period.~~

Section IV. Specific Operating Conditions (continued)

D. Emission Unit S2.007 (continued)

3. Emission Limits (NAC 445B.305, NAC 445B.3405) (continued)
The Permittee, upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from **S2.007** the following pollutants in excess of the following specified limits:
   f. The discharge of **NO_X** (oxides of nitrogen) to the atmosphere shall not exceed:
      (1) **9** parts per million by volume (ppmv) at 15 percent oxygen and on a dry basis, based on a 24-hour rolling period;
      (2) **42.0** pounds per hour, based on a 720-hour rolling period;
      (3) **122.64** tons per year, based on a 12-month rolling period.
   ~~g. The discharge of **CO** (carbon monoxide) to the atmosphere shall not exceed:~~
      ~~(1) **25** ppmv, based on a 24-hour block average.~~
      ~~(2) **54.0** pounds per hour, based on a 720-hour rolling period.~~
      ~~(3) **115.0** pounds per hour, based on a 60-minute rolling period.~~
      ~~(4) **205.86** tons per year, based on a 12-month rolling period.~~
   ~~h. The discharge of **VOCs** (volatile organic compounds) to the atmosphere shall not exceed **4.25** pounds per hour, nor more than **18.6** tons per 12-month rolling period.~~
   ~~i. NAC 445B.22017 – The opacity from the **S2.007** shall not equal or exceed **20** percent.~~

~~4. Specific Acid Rain Requirements (NAC 445B.305, 40 CFR 72.9, 40 CFR 73.10(b)(2))~~
   ~~a. The Permittee shall not exceed the SO_2 emission levels (acid rain allowances) for the indicated years as shown in Table B-1 below without holding the required acid rain allowances in accordance with Section **I.Y.2.** of this Operating Permit and pursuant to 40 CFR Part 72.9, and specified in Table 2 of 40 CFR Part 73.10(b)(2):~~

~~**Table D-1: Acid Rain Allowance Allocations**~~						
~~**S2.006**~~	~~**Phase II (Years 2010 and Beyond) Utility Boilers > 25 MW Output Capacity**~~	~~**2017**~~	~~**2018**~~	~~**2019**~~	~~**2020**~~	~~**2021**~~
		~~*0*~~	~~*0*~~	~~*0*~~	~~*0*~~	~~*0*~~

   ~~b. The Permittee shall comply with the "Standard Requirements" provisions of the SO_2 acid rain permit application dated **December 12, 2013** entitled "Acid Rain Permit Application – For Acid Rain Permit Renewal" and all references contained therein, as submitted with the Permittee's application for renewal of Class I Air Quality Operating Permit.~~

~~5. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405)~~
~~The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record.~~
   ~~a. Monitor and record the hours of operation for **S2.007** on a daily basis.~~
   ~~b. Calibrate, operate, and maintain a fuel flow meter to continuously measure the volume of **Pipeline Quality Natural Gas** consumed in **S2.007** (in standard cubic feet or hundreds of standard cubic feet). The fuel flow meter shall be installed at an appropriate location in the fuel delivery system to accurately and continuously measure the fuel consumed in **S2.007** in accordance with the requirements prescribed in 40 CFR Part 75.~~
   ~~c. Calibrate, operate, and maintain a Continuous Data Collection System (CDCS) to continuously record the quantity (in standard cubic feet or hundreds of standard cubic feet) of **Pipeline Quality Natural Gas** as measured by the fuel flow meter required under D.**5.b.** of this section. The CDCS will be installed, calibrated, operated and maintained in accordance with the manufacturer's specifications and requirements prescribed in 40 CFR Part 75.~~

Section IV. Specific Operating Conditions (continued)

D. Emission Unit S2.007 (continued)

~~5. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405) (continued)~~

~~The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record.~~

~~d. Determine the gross calorific value (GCV) of **Pipeline Quality Natural Gas** consumed in **S2.007** by sampling the **Pipeline Quality Natural Gas** in **S2.007** on a monthly basis. The GCV of the gas sample shall be determined using one of the following methods: ASTM D1826-94; ASTM D3588-98; ASTM D4891-89; Gas Processors Association (GPA) Standard 2172-96; Calculation of Gross Heating Value; Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis; or GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography. Alternatively, at least once each month, the GCV may be verified by the contractual supplier, or the Permittee may use a maximum GCV value of 1,060 Btu/scf. If the supplier certification is used to verify the GCV, the supplier must provide documentation identifying the test method(s) used to determine the GCV.~~

~~e. Missing GCV or fuel flow data may be substituted as prescribed in 40 CFR Part 75, Appendix D.~~

~~f. The hourly heat input of the **Pipeline Quality Natural Gas** (in MMBtu/hr) combusted will be calculated from the hourly fuel usage recorded in **D.5.c.** of this section.~~

~~Sample Calculation:~~

~~(scf Natural Gas/hr)(Btu/scf) = Btu/hr or MMBtu/hr~~

~~g. The hourly emission rate of PM, PM_{10}, $PM_{2.5}$, CO, and VOC, each, in pounds per hour (lbs/hr) will be calculated from the hourly quantity of **Pipeline Quality Natural Gas** combusted determined in **D.5.c.** of this section, and the emission factor derived in **D.6.l.** of this section.~~

~~Sample Calculation:~~

~~(scf/hr)(lbs pollutant/scf) = lbs pollutant/hr~~

~~or~~

~~(MMBtu/hr)(lbs pollutant/MMBtu) = lbs pollutant/hr~~

~~h. The hourly emission rate of PM, PM_{10}, $PM_{2.5}$, CO, and VOC, each in pounds per MMBtu (lbs/MMbtu) will be calculated from the heat content of the fuel determined in **D.5.d.** of this section, and the emission factor derived in **D.6.l.** of this section.~~

~~Sample Calculation:~~

~~(scf/Btu)(lb pollutant/scf) = lbs pollutant/Btu or lbs pollutant/MMBtu~~

~~i. Calculate annually the SO_2 emissions in tons based on quantity of **Pipeline Quality Natural Gas** determined in **D.5.c.** of this section and sulfur in units of grains per dry standard cubic feet of **Pipeline Quality Natural Gas** from the SO_2 emission factor for **Pipeline Quality Natural Gas** combusted from 40 CFR Part 75 Appendix D.~~

Section IV. Specific Operating Conditions (continued)

D. Emission Unit S2.007 (continued)

~~6. Performance and Compliance Testing (NAC 445B.3405, (NAC 445B.252(1))~~
~~The Permittee, upon issuance of this operating permit, shall conduct and record renewal performance testing at least 90 days prior to the expiration of this operating permit, but no earlier than 365 days from the date of expiration of this operating permit, and every 5 years thereafter, in accordance with the following:~~

~~a. All opacity compliance demonstrations and performance tests must comply with the advance notification, protocol review, operational conditions, reporting, and other requirements of Section **I.I.**, Testing and Sampling (NAC 445B.252), of this operating permit. Material sampling must be conducted in accordance with protocols approved by the Director. All performance test results shall be based on the arithmetic average of three valid runs. (NAC 445B.252(5))~~

~~b. Testing shall be conducted on the exhaust stack of **S2.007**.~~

~~c. Method 5 in Appendix A of 40 CFR Part 60 shall be used to determine PM emissions. The sample volume for each test run shall be at least 1.7 dscm (60 dscf). Test runs must be conducted for up to two hours in an effort to collect this minimum sample.~~

~~d. Method 201A and Method 202 in Appendix M of 40 CFR Part 51 shall be used to determine~~ $\cancel{PM_{10}}$ ~~and~~ $\cancel{PM_{2.5}}$ ~~emissions. The sample time and sample volume collected for each test run shall be sufficient to collect enough mass to weigh accurately.~~

~~e. The Method 201A and 202 test required in this section may be replaced by a Method 5 in Appendix A of 40 CFR Part 60 and Method 202 in Appendix M of 40 CFR Part 51 test. All particulate captured in the Method 5 and Method 202 test performed under this provision shall be considered~~ $\cancel{PM_{2.5}}$ ~~for determination of compliance.~~

~~f. Method 7E in Appendix A of 40 CFR Part 60 shall be used to determine the nitrogen oxides concentration. Each test will be run for a minimum of one hour.~~

~~g. Method 9 in Appendix A of 40 CFR Part 60 shall be used to determine opacity. Opacity observations shall be conducted concurrently with the applicable performance test. The minimum total time of observations shall be six minutes (24 consecutive observations recorded at 15 second intervals), unless otherwise specified by an applicable subpart.~~

~~h. Method 10 in Appendix A of 40 CFR Part 60 shall be used to determine the carbon monoxide concentration. Each test will be run for a minimum of one hour.~~

~~i. Method 25A in Appendix A of 40 CFR Part 60 shall be used to determine the volatile organic compound concentration. Method 18 in Appendix A of 40 CFR Part 60 or Method 320 in Appendix A of CFR Part 63 may be used in conjunction with Method 25A to break out the organic compounds that are not considered VOC's by definition per 40 CFR 51.100(s). Each Method 25A test will be run for a minimum of one hour.~~

~~j. The performance tests required in **D.6.c.** through **D.6.i.** of this section shall be conducted at the best achievable heat input rate at normal operating conditions, unless otherwise approved pursuant to NAC 445B.252. Should any anticipated major boiler overhaul(s) be scheduled to be performed, which coincide with the performance tests, the performance testing shall be performed prior to the overhaul(s). If the performance testing cannot be performed prior to a major boiler overhaul(s), the performance testing shall be performed as soon as practicable following the overhaul(s), but not earlier than 60 days following the overhaul(s).~~

~~k. The Permittee shall record the quantity of **Pipeline Quality Natural Gas** combusted (in standard cubic feet or hundreds of standard cubic feet) for each test run and the heat content (in Btu/scf) for each performance test event.~~

Section IV. Specific Operating Conditions (continued)

D. Emission Unit S2.007 (continued)

~~6. Performance and Compliance Testing (NAC 445B.3405, (NAC 445B.252(1)) (continued)~~
~~The Permittee, upon issuance of this operating permit, shall conduct and record renewal performance testing at least 90 days prior to the expiration of this operating permit, but no earlier than 365 days from the date of expiration of this operating permit, and every 5 years thereafter, in accordance with the following:~~

~~l. Using the most recent performance tests, as specified above, the Permittee shall calculate the following emission factors, based on the average of 3 test runs:~~
- ~~(1) Pounds of PM per scf (lbs PM/scf) of Pipeline Quality Natural Gas, or pounds of PM per MMBtu (lbs PM/MMBtu) of Pipeline Quality Natural Gas.~~
- ~~(2) Pounds of PM_{10} per scf (lbs PM_{10}/scf) of Pipeline Quality Natural Gas, or pounds of PM_{10} per MMBtu (lbs PM_{10}/MMBtu) of Pipeline Quality Natural Gas.~~
- ~~(3) Pounds of $PM_{2.5}$ per scf (lbs $PM_{2.5}$/scf) of Pipeline Quality Natural Gas, or pounds of $PM_{2.5}$ per MMBtu (lbs PM_{10}/MMBtu) of Pipeline Quality Natural Gas.~~
- ~~(4) Pounds of NO_X per scf (lbs NO_X/scf) of Pipeline Quality Natural Gas, or pounds of NO_X per MMBtu (lbs NO_X/MMBtu) of Pipeline Quality Natural Gas.~~
- ~~(5) Pounds of CO per scf (lbs CO/scf) of Pipeline Quality Natural Gas, or pounds of CO per MMBtu (lbs CO/MMBtu) of Pipeline Quality Natural Gas.~~
- ~~(6) Pounds of VOC per scf (lbs VOC/scf) of Pipeline Quality Natural Gas, or pounds of VOC per MMBtu (lbs VOC/MMBtu) of Pipeline Quality Natural Gas.~~

~~7. Federal Requirements~~

~~a. Standards of Performance for New Stationary Sources – 40 CFR Part 60 Subpart GG – Standards of Performance for Stationary Gas Turbines~~

~~(1) Standards for Nitrogen Oxides (40 CFR 60.332)~~
~~On and after the date on which the performance test required by 40 CFR Part 60.8 is completed, the Permittee shall not discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxide in excess of what is calculated in the equation under 40 CFR Part 60.332(a)(1). (40 CFR 60.332(a)(1))~~

~~(2) Standard for Sulfur Dioxide (40 CFR 60.333)~~
~~On and after the date on which the performance test required to be conducted by 40 CFR Part 60.8 is completed, the Permittee shall comply with one or the other of the following conditions:~~
- ~~(a) The Permittee shall not cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of **0.0015** percent by volume at 15 percent oxygen on a dry basis. (40 CFR 60.333(a))~~
- ~~(b) The Permittee shall not burn in any stationary gas turbine any fuel which contains total sulfur in excess of **0.8** percent by weight (8,000 ppmw). (40 CFR 60.333(b))~~

~~(3) Monitoring of Operations (40 CFR 60.334)~~
- ~~(a) Except as provided in 40 CFR Part 60.334(b), the Permittee shall install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine while combusting No. 2 Distillate Fuel Oil under "Emergency" conditions defined in **D.2.c.** of this section. (40 CFR 60.334(a))~~
- ~~(b) The Permittee may, as an alternative to operating the continuous monitoring system described in 40 CFR Part 60.334(a), install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F-14a or F-14b in Appendix F to 40 CFR Part 75 and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained as stated in 40 CFR Parts 60.334(b)(1) through 60.334(b)(3). (40 CFR 60.334(b))~~

Issued to: SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY – TRACY POWER GENERATING STATION (AS PERMITTEE)

Section IV. Specific Operating Conditions (continued)

F. Emission Units S2.009 and S2.009.1

System 07C – Tracy Unit #4 Piñon Pine Combustion Turbine/Duct Burner – Pipeline Quality Natural Gas		Location UTM (Zone 11, NAD 83)	
		m North	m East
S2.009	Combustion Turbine/HRSG (Manufactured by General Electric; Model MS6001FA; Serial 1646; Maximum Heat Input 763.9 MMBtu/hr; Nominal Output 107 MW)	4,382,292	283,159
S2.009.1	Duct Burner (Manufactured by Forney; Maximum Heat Input 156.464 MMBtu/hr; Nominal Output 23 MW)	4,382,292	283,159

1. Air Pollution Control Equipment (NAC 445B.3405)
   a. Emissions from **S2.009** shall be controlled by a **Steam Injection** for control of NO_X.
   b. Emissions from **S2.009.1** shall be controlled by **Dry Low NO_X Burners**. Note, these are not add-on controls.
   ~~c. Emissions from **S2.009 and S2.009.1** are discharged through the same exhaust stack.~~
   ~~d. Descriptive Stack Parameters~~
   ~~Stack Height: 225.0 feet~~
   ~~Stack Diameter: 12.0 feet~~
   ~~Stack Temperature: 366.5 °F~~

~~2. Operating Parameters (NAC 445B.3405)~~
   ~~a. **S2.009 and S2.009.1** may consume only **Pipeline Quality Natural Gas**.~~
   ~~b. The maximum allowable heat input rate for **S2.009 and S2.009.1**, combined, shall not exceed **920.36 million Btu (MMBtu)** per any one-hour period.~~
   ~~c. Hours~~
   ~~(1) **S2.009 and S2.009.1** , each, may operate a total of **24** hours per day.~~

~~3. Emission Limits (NAC 445B.305, NAC 445B.3405)~~
   ~~The Permittee, upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from the exhaust stack of **S2.009 and S2.009.1** the following pollutants in excess of the following specified limits:~~
   ~~a. The discharge of **PM** (particulate matter) to the atmosphere shall not exceed **20.1** pounds per hour, nor more than **29.9** tons per 12-month rolling period.~~
   ~~b. The discharge of **PM_{10}** (particulate matter less than or equal to 10 microns in diameter) to the atmosphere shall not exceed **20.1** pounds per hour, nor more than **19.9** tons per 12-month rolling period.~~
   ~~c. NAC 445B.2203 – The maximum allowable discharge of **PM_{10}** to the atmosphere from the exhaust **S2.009 and S2.009.1** shall not exceed **0.21** pounds per MMBtu.~~
   ~~d. The discharge of **$PM_{2.5}$** (particulate matter less than or equal to 2.5 microns in diameter) to the atmosphere shall not exceed **20.1** pounds per hour, nor more than **19.9** tons per 12-month rolling period.~~
   ~~e. The discharge of **SO_2** (sulfur dioxide) to the atmosphere shall not exceed **0.54** pound per hour, nor more than **2.42** tons per 12-month rolling period.~~
   ~~f. The discharge of **NO_X** (oxides of nitrogen) to the atmosphere shall not exceed **141.0** pounds per hour, nor more than **533.1** tons per 12-month rolling period.~~
   ~~g. The discharge of **CO** (carbon monoxide) to the atmosphere shall not exceed **34.4** pounds per hour, nor more than **118.8** tons per 12-month rolling period.~~
   ~~h. The discharge of **VOCs** (volatile organic compounds) to the atmosphere shall not exceed **5.40** pounds per hour, nor more than **54.47** tons per 12-month rolling period.~~
   ~~i. NAC 445B.22017 – The opacity from the exhaust stack of **S2.009 and S2.009.1** shall not equal or exceed **20** percent.~~

Issued to: SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY – TRACY POWER GENERATING STATION (AS PERMITTEE)

Section IV. Specific Operating Conditions (continued)

F. Emission Units S2.009 and S2.009.1 (continued)

~~4. Specific Acid Rain Requirements (NAC 445B.305, 40 CFR 72.9, 40 CFR 73.10(b)(2))~~

~~a. The Permittee shall not exceed the SO_2 emission levels (acid rain allowances) for the indicated years as shown in Table B-1 below without holding the required acid rain allowances in accordance with Section **I.Y.2.** of this Operating Permit and pursuant to 40 CFR Part 72.9, and specified in Table 2 of 40 CFR Part 73.10(b)(2):~~

~~**Table F-1: Acid Rain Allowance Allocations**~~						
~~**S2.007**~~	~~**Phase II (Years 2010 and Beyond) Utility Boilers > 25 MW Output Capacity**~~	~~**2017**~~	~~**2018**~~	~~**2019**~~	~~**2020**~~	~~**2021**~~
		~~*0*~~	~~*0*~~	~~*0*~~	~~*0*~~	~~*0*~~

~~b. The Permittee shall comply with the "Standard Requirements" provisions of the SO_2 acid rain permit application dated **December 12, 2013** entitled "Acid Rain Permit Application – For Acid Rain Permit Renewal" and all references contained therein, as submitted with the Permittee's application for renewal of Class I Air Quality Operating Permit.~~

~~5. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405)~~

~~The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record.~~

~~a. Monitor and record the hours of operation for **S2.009 and S2.009.1** on a daily basis.~~

~~b. Calibrate, operate, and maintain a fuel flow meter to continuously measure the volume of **Pipeline Quality Natural Gas** consumed in **S2.009 and S2.009.1** (in standard cubic feet or hundreds of standard cubic feet). The fuel flow meter shall be installed at an appropriate location in the fuel delivery system to accurately and continuously measure the fuel consumed in **S2.009 and S2.009.1** in accordance with the requirements prescribed in 40 CFR Part 75.~~

~~c. Calibrate, operate, and maintain a Continuous Data Collection System (CDCS) to continuously record the quantity (in standard cubic feet or hundreds of standard cubic feet) of **Pipeline Quality Natural Gas** as measured by the fuel flow meter required under **F.5.b.** of this section. The CDCS will be installed, calibrated, operated and maintained in accordance with the manufacturer's specifications and requirements prescribed in 40 CFR Part 75.~~

~~d. Determine the gross calorific value (GCV) of **Pipeline Quality Natural Gas** consumed in **S2.009 and S2.009.1** by sampling the **Pipeline Quality Natural Gas** in **S2.009 and S2.009.1** on a monthly basis. The GCV of the gas sample shall be determined using one of the following methods: ASTM D1826-94; ASTM D3588-98; ASTM D4891-89; Gas Processors Association (GPA) Standard 2172-96; Calculation of Gross Heating Value; Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis; or GPA Standard 2261-00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography. Alternatively, at least once each month, the GCV may be verified by the contractual supplier, or the Permittee may use a maximum GCV value of 1,060 Btu/scf. If the supplier certification is used to verify the GCV, the supplier must provide documentation identifying the test method(s) used to determine the GCV.~~

Section IV. Specific Operating Conditions (continued)

F. Emission Units S2.009 and S2.009.1 (continued)

~~5. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405) (continued)~~

~~The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.~~

~~e. Missing GCV or fuel flow data may be substituted as prescribed in 40 CFR Part 75, Appendix D.~~

~~f. The hourly heat input of the **Pipeline Quality Natural Gas** (in MMBtu/hr) combusted will be calculated from the hourly fuel usage recorded in **F.5.c.** of this section.~~

~~**Sample Calculation:**~~

~~**(scf Natural Gas/hr)(Btu/scf) = Btu/hr or MMBtu/hr**~~

~~g. The hourly emission rate of PM, PM_{10}, $PM_{2.5}$, CO, and VOC, each, in pounds per hour (lbs/hr) will be calculated from the hourly quantity of **Pipeline Quality Natural Gas** combusted determined in **F.5.c.** of this section, and the emission factor derived in **F.6.a.(11)** of this section.~~

~~**Sample Calculation:**~~

~~**(scf/hr)(lbs pollutant/scf) = lbs pollutant/hr**~~

~~**or**~~

~~**(MMBtu/hr)(lbs pollutant/MMBtu) = lbs pollutant/hr**~~

~~h. The hourly emission rate of PM, PM_{10}, $PM_{2.5}$, CO, and VOC, each in pounds per MMBtu (lbs/MMbtu) will be calculated from the heat content of the fuel determined in **F.5.d.** of this section, and the emission factor derived in **F.6.a.(11)** of this section.~~

~~**Sample Calculation:**~~

~~**(scf/Btu)(lb pollutant/scf) = lbs pollutant/Btu or lbs pollutant/MMBtu**~~

~~i. Calculate annually the SO_2 emissions in tons based on quantity of **Pipeline Quality Natural Gas** determined in **F.5.c.** of this section and sulfur in units of grains per dry standard cubic feet of **Pipeline Quality Natural Gas** from the SO_2 emission factor for **Pipeline Quality Natural Gas** combusted from 40 CFR Part 75 Appendix D.~~

Section IV. Specific Operating Conditions (continued)

F. Emission Units S2.009 and S2.009.1 (continued)

~~6. Performance and Compliance Testing (NAC 445B.3405, (NAC 445B.252(1))~~

~~a. The Permittee, upon issuance of this operating permit, shall conduct and record renewal performance testing at least 90 days prior to the expiration of this operating permit, but no earlier than 365 days from the date of expiration of this operating permit, and every 5 years thereafter, in accordance with the following:~~

~~(1) All performance tests must comply with the advance notification, protocol review, operational conditions, reporting, and other requirements of Section **I.I.**, Testing and Sampling (NAC 445B.252), of this operating permit. Material sampling must be conducted in accordance with protocols approved by the Director. All performance test results shall be based on the arithmetic average of three valid runs. (NAC 445B.252(5))~~

~~(2) Testing shall be conducted on the exhaust stack of **S2.009 and S2.009.1**.~~

~~(3) Method 5 in Appendix A of 40 CFR Part 60 shall be used to determine PM emissions. The sample volume for each test run shall be at least 1.7 dscm (60 dscf). Test runs must be conducted for up to two hours in an effort to collect this minimum sample.~~

~~(4) Method 201A and Method 202 in Appendix M of 40 CFR Part 51 shall be used to determine PM_{10} and $PM_{2.5}$ emissions. The sample time and sample volume collected for each test run shall be sufficient to collect enough mass to weigh accurately.~~

~~(5) The Method 201A and 202 test required in this section may be replaced by a Method 5 in Appendix A of 40 CFR Part 60 and Method 202 in Appendix M of 40 CFR Part 51 test. All particulate captured in the Method 5 and Method 202 test performed under this provision shall be considered $PM_{2.5}$ for determination of compliance.~~

~~(6) Method 7E in Appendix A of 40 CFR Part 60 shall be used to determine the nitrogen oxides concentration. Each test will be run for a minimum of one hour.~~

~~(7) Method 10 in Appendix A of 40 CFR Part 60 shall be used to determine the carbon monoxide concentration. Each test will be run for a minimum of one hour.~~

~~(8) Method 25A in Appendix A of 40 CFR Part 60 shall be used to determine the volatile organic compound concentration. Method 18 in Appendix A of 40 CFR Part 60 or Method 320 in Appendix A of CFR Part 63 may be used in conjunction with Method 25A to break out the organic compounds that are not considered VOC's by definition per 40 CFR 51.100(s). Each Method 25A test will be run for a minimum of one hour.~~

~~(9) The performance tests required in **F.6.a.(1).** through **F.6.a.(8).** of this section shall be conducted at the best achievable heat input rate at normal operating conditions, unless otherwise approved pursuant to NAC 445B.252. Should any anticipated major boiler overhaul(s) be scheduled to be performed, which coincide with the performance tests, the performance testing shall be performed prior to the overhaul(s). If the performance testing cannot be performed prior to a major boiler overhaul(s), the performance testing shall be performed as soon as practicable following the overhaul(s), but not earlier than 60 days following the overhaul(s).~~

~~(10) The Permittee shall record the quantity of **Pipeline Quality Natural Gas** combusted (in standard cubic feet or hundreds of standard cubic feet) for each test run and the heat content (in Btu/scf) for each performance test event.~~

~~(11) Using the most recent performance tests, as specified above, the Permittee shall calculate the following emission factors, based on the average of 3 test runs:~~

~~(a) Pounds of PM per scf (lbs-PM/scf) of Pipeline Quality Natural Gas, or pounds of PM per MMBtu (lbs-PM/MMBtu) of Pipeline Quality Natural Gas.~~

~~(b) Pounds of PM_{10} per scf (lbs-PM_{10}/scf) of Pipeline Quality Natural Gas, or pounds of PM_{10} per MMBtu (lbs-PM_{10}/MMBtu) of Pipeline Quality Natural Gas.~~

~~(c) Pounds of $PM_{2.5}$ per scf (lbs-$PM_{2.5}$/scf) of Pipeline Quality Natural Gas, or pounds of $PM_{2.5}$ per MMBtu (lbs-PM_{10}/MMBtu) of Pipeline Quality Natural Gas.~~

~~(d) Pounds of NO_X per scf (lbs-NO_X/scf) of Pipeline Quality Natural Gas, or pounds of NO_X per MMBtu (lbs-NO_X/MMBtu) of Pipeline Quality Natural Gas.~~

~~(e) Pounds of CO per scf (lbs-CO/scf) of Pipeline Quality Natural Gas, or pounds of CO per MMBtu (lbs-CO/MMBtu) of Pipeline Quality Natural Gas.~~

~~(f) Pounds of VOC per scf (lbs-VOC/scf) of Pipeline Quality Natural Gas, or pounds of VOC per MMBtu (lbs-VOC/MMBtu) of Pipeline Quality Natural Gas.~~

Section IV. Specific Operating Conditions (continued)

F. Emission Units S2.009 and S2.009.1 (continued)

~~6. Performance and Compliance Testing (NAC 445B.3405, (NAC 445B.252(1)) (continued)~~

~~b. The Permittee, upon issuance of this operating permit, shall conduct and record annual opacity compliance demonstrations within 90 days of the anniversary date of the previous initial opacity compliance demonstrations or annual opacity compliance demonstrations, and annually thereafter, in accordance with the following:~~

~~(1) All opacity compliance demonstrations must comply with the advance notification, protocol review, operational conditions, reporting, and other requirements of Section **I.I.** Testing and Sampling (NAC 445B.252) of this operating permit.~~

~~(2) Opacity compliance demonstrations shall be conducted on the exhaust stack of **S2.009 and S2.009.1**.~~

~~(3) Method 9 in Appendix A of 40 CFR Part 60 shall be used to determine opacity. Opacity observations shall be conducted concurrently with the applicable performance test. The minimum total time of observations shall be six minutes (24 consecutive observations recorded at 15 second intervals), unless otherwise specified by an applicable subpart.~~

~~(4) The opacity compliance demonstrations required in **F.6.b.(1)** through **F.6.b.(3)** of this section shall be conducted at the best achievable heat input rate at normal operating conditions, unless otherwise approved pursuant to NAC 445B.252. Should any anticipated major boiler overhaul(s) be scheduled to be performed, which coincide with the opacity compliance demonstrations, the opacity compliance demonstrations shall be performed prior to the overhaul(s). If the opacity compliance demonstrations cannot be performed prior to a major boiler overhaul(s), the opacity compliance demonstrations shall be performed as soon as practicable following the overhaul(s), but not earlier than 60 days following the overhaul(s).~~

~~7. Federal Requirements~~

~~a. Standards of Performance for New Stationary Sources – 40 CFR Part 60 Subpart GG – Standards of Performance for Stationary Gas Turbines~~

~~(1) Standards for Nitrogen Oxides (40 CFR 60.332)~~

~~On and after the date on which the performance test required by 40 CFR Part 60.8 is completed, the Permittee shall not discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxide in excess of what is calculated in the equation under 40 CFR Part 60.332(a)(1). (40 CFR 60.332(a)(1))~~

~~(2) Standard for Sulfur Dioxide (40 CFR 60.333)~~

~~On and after the date on which the performance test required to be conducted by 40 CFR Part 60.8 is completed, the Permittee shall comply with one or the other of the following conditions:~~

~~(a) The Permittee shall not cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of **0.0015** percent by volume at 15 percent oxygen on a dry basis. (40 CFR 60.333(a))~~

~~(b) The Permittee shall not burn in any stationary gas turbine any fuel which contains total sulfur in excess of **0.8** percent by weight (8,000 ppmw). (40 CFR 60.333(b))~~

~~(3) Monitoring of Operations (40 CFR 60.334)~~

~~(a) Except as provided in 40 CFR Part 60.334(b), the Permittee shall install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. (40 CFR 60.334(a))~~

~~(b) The Permittee may, as an alternative to operating the continuous monitoring system described in 40 CFR Part 60.334(a), install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O_2 monitors. As an alternative, a CO_2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O_2 by either converting the CO_2 hourly averages to equivalent O_2 concentrations using Equation F-14a or F-14b in Appendix F to 40 CFR Part 75 and making the adjustments to 15 percent O_2, or by using the CO_2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained as stated in 40 CFR Parts 60.334(b)(1) through 60.334(b)(3). (40 CFR 60.334(b))~~

Section IV. Specific Operating Conditions (continued)

L. Emission Units S2.064 and S2.065

System 32 – Combined Cycle Combustion Turbine Circuit No. 8 – Pipeline Quality Natural Gas – 254 MW Nominal Output		Location UTM (Zone 11, NAD 83)	
		m North	m East
S2.064	Combined Cycle Combustion Turbine #8 (Manufactured by General Electric; Serial CT8-298613; Date 2007; Maximum Heat Input Rate 1,862.0 MMBtu/hr)	4,382,139	283,145
S2.065	Duct Burner #8 (Manufactured by Nooter; Serial DB-22896A; Date 2007; Maximum Heat Input Rate 660.0 MMBtu/hr) & Heat Recovery Steam Generator #8 (Manufactured by General Electric; Serial HRSG8-CP28-08-01; Date 2007)	4,382,139	283,145

1. Air Pollution Control Equipment (NAC 445B.3405)
   a. NO_X emissions from **S2.064 and S2.065** shall be controlled by a **Selective Catalytic Reduction (SCR)**. The SCR shall utilize Ammonia Injection into the SCR at a volume specified by the manufacturer.
   ~~b. CO and VOC emissions from **S2.064 and S2.065** shall be controlled by an **Oxidation Catalyst** for control.~~
   ~~c. Emissions from **S2.064 and S2.065** are discharged through the same exhaust stack.~~
   ~~d. Descriptive Stack Parameters~~
   ~~Stack Height: 150.0 feet~~
   ~~Stack Diameter: 18.0 feet~~
   ~~Stack Temperature: 173 °F~~
   ~~Exhaust Flow: 960,000 dry standard cubic feet per minute (dscfm)~~

~~2. Operating Parameters (NAC 445B.3405)~~
   ~~a. **S2.064 and S2.065** may consume only **Pipeline Quality Natural Gas**.~~
   ~~b. The maximum allowable heat input rate for **S2.064 and S2.065**, combined, shall not exceed **2,522.0 million Btu (MMBtu)** per any one-hour period.~~
   ~~c. The maximum allowable fuel consumption rate for **S2.064 and S2.065**, combined, shall not exceed **2,475,000.0 standard cubic feet (scf)** per any one-hour period.~~
   ~~d. Hours~~
   ~~(1) **S2.064 and S2.065**, each, may operate a total of **24** hours per day.~~

3. Emission Limits (NAC 445B.305, NAC 445B.3405)
   The Permittee, upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from the exhaust stack of **S2.064 and S2.065** the following pollutants in excess of the following specified limits:
   ~~a. The discharge of **PM** (particulate matter) to the atmosphere shall not exceed **25.0** pounds per hour, nor more than **109.5** tons per 12-month rolling period.~~
   ~~b. The discharge of **PM_{10}** (particulate matter less than or equal to 10 microns in diameter) to the atmosphere shall not exceed **25.0** pounds per hour, nor more than **109.5** tons per 12-month rolling period.~~
   ~~c. BACT Emission Limit – The discharge of **PM_{10}** to the atmosphere shall not exceed **0.011** pounds per million Btu (MMBtu), filterable and condensable, based on a 3-hour rolling period.~~
   ~~d. The discharge of **$PM_{2.5}$** (particulate matter less than or equal to 2.5 microns in diameter) to the atmosphere shall not exceed **25.0** pounds per hour, nor more than **109.5** tons per 12-month rolling period.~~
   ~~e. The discharge of **SO_2** (sulfur dioxide) to the atmosphere shall not exceed **2.0** pound per hour, nor more than **8.76** tons per 12-month rolling period.~~
   ~~f. The discharge of **NO_X** (oxides of nitrogen) to the atmosphere shall not exceed **20.0** pounds per hour (based on a 3-hour rolling period), nor more than **87.6** tons per 12-month rolling period.~~
   g. BACT Emission Limit – The discharge of **NO_X** to the atmosphere shall not exceed **2.0** parts per million by volume (ppmv) at 15 percent oxygen on a dry basis, based on a 3-hour rolling period.
   ~~h. The discharge of **CO** (carbon monoxide) to the atmosphere shall not exceed **12.0** pounds per hour, nor more than **52.6** tons per 12-month rolling period.~~
   ~~i. BACT Emission Limit – The discharge of **CO** to the atmosphere shall not exceed **3.5** ppmv at 15 percent oxygen on a dry basis, based on a 3-hour rolling period.~~

Section IV. Specific Operating Conditions (continued)

L. Emission Units S2.064 and S2.065 (continued)

3. Emission Limits (NAC 445B.305, NAC 445B.3405) (continued)
The Permittee, upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from the exhaust stack of **S2.064 and S2.065** the following pollutants in excess of the following specified limits:
   - ~~j. The discharge of **VOCs** (volatile organic compounds) to the atmosphere shall not exceed **7.5** pounds per hour, nor more than **32.9** tons per 12-month rolling period.~~
   - ~~k. BACT Emission Limit – The discharge of **VOCs** to the atmosphere shall not exceed **4.0** ppmv at 15 percent oxygen on a dry basis, based on a 3-hour rolling period.~~
   - ~~l. BACT Emission Limit – The discharge of **Sulfuric Acid Mist** to the atmosphere shall not exceed **1.00** pounds per hour, nor more than **4.40** tons per 12-month rolling period.~~
   - ~~m. NAC 445B.22017 – The opacity from the exhaust stack of **S2.064 and S2.065**, combined, shall not equal or exceed **20** percent.~~
   - ~~n. NAC 445B.2203 – The maximum allowable discharge of **PM$_{10}$** to the atmosphere from the exhaust **S2.064 and S2.065**, combined, shall not exceed **0.17** pounds per MMBtu.~~

~~4. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405)~~
~~The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record.~~
   - ~~a. Monitor and record the hours of operation for **S2.064 and S2.065** on a daily basis.~~
   - ~~b. Calibrate, operate, and maintain a fuel flow meter to continuously measure the volume of **Pipeline Quality Natural Gas** consumed in **S2.064 and S2.065** (in standard cubic feet or hundreds of standard cubic feet). The fuel flow meter shall be installed at an appropriate location in the fuel delivery system to accurately and continuously measure the fuel consumed in **S2.064 and S2.065** in accordance with the requirements prescribed in 40 CFR Part 75.~~
   - ~~c. Calibrate, operate, and maintain a Continuous Data Collection System (CDCS) to continuously record the quantity (in standard cubic feet or hundreds of standard cubic feet) of **Pipeline Quality Natural Gas** as measured by the fuel flow meter required under **L.5.b.** of this section. The CDCS will be installed, calibrated, operated and maintained in accordance with the manufacturer's specifications and requirements prescribed in 40 CFR Part 75.~~
   - ~~d. Missing GCV or fuel flow data may be substituted as prescribed in 40 CFR Part 75, Appendix D.~~
   - ~~e. Monitor and record the heat content of the **Pipeline Quality Natural Gas** combusted (in Btu per standard cubic feet). The heat content of the **Pipeline Quality Natural Gas** will be based on the supplier's data and specifications.~~
   - ~~f. The hourly heat input of the **Pipeline Quality Natural Gas** (in MMBtu/hr) combusted will be calculated from the hourly fuel usage recorded in **L.5.c.** of this section.~~

~~**Sample Calculation:**~~

~~**(scf Natural Gas/hr)(Btu/scf) = Btu/hr or MMBtu/hr**~~

   - ~~g. The hourly emission rate of PM, PM$_{10}$, PM$_{2.5}$, VOC, and Sulfuric Acid Mist, each, in pounds per hour (lbs/hr) will be calculated from the hourly quantity of **Pipeline Quality Natural Gas** combusted determined in **L.5.c.** of this section, and the emission factor derived in **L.6.m.** of this section.~~

~~**Sample Calculation:**~~

~~**(scf/hr)(lbs pollutant/scf) = lbs pollutant/hr**~~

~~**or**~~

~~**(MMBtu/hr)(lbs pollutant/MMBtu) = lbs pollutant/hr**~~

Section IV. Specific Operating Conditions (continued)

L. Emission Units S2.064 and S2.065 (continued)

~~4. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405) (continued)~~
~~The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.~~

~~h. The hourly emission rate of PM,~~ ~~PM_{10}, $PM_{2.5}$~~~~, VOC, and Sulfuric Acid Mist, each in pounds per MMBtu (lbs/MMbtu) will be calculated from the heat content of the fuel determined in **L.5.c.** of this section, and the emission factor derived in **L.6.m.** of this section.~~

~~Sample Calculation:~~

~~(scf/Btu)(lb pollutant/scf) = lbs pollutant/Btu or lbs pollutant/MMBtu~~

~~i. Calculate annually the~~ ~~SO_2~~ ~~emissions in tons based on quantity of **Pipeline Quality Natural Gas** determined in **L.5.c.** of this section and sulfur in units of grains per dry standard cubic feet of **Pipeline Quality Natural Gas** from the~~ ~~SO_2~~ ~~emission factor for **Pipeline Quality Natural Gas** combusted from 40 CFR Part 75 Appendix D.~~

~~5. Performance and Compliance Testing (NAC 445B.3405, (NAC 445B.252(1))~~
~~The Permittee, upon issuance of this operating permit, shall conduct and record renewal performance testing at least 90 days prior to the expiration of this operating permit, but no earlier than 365 days from the date of expiration of this operating permit, and every 5 years thereafter, in accordance with the following:~~

~~a. All opacity compliance demonstrations and performance tests must comply with the advance notification, protocol review, operational conditions, reporting, and other requirements of Section **I.I.**, Testing and Sampling (NAC 445B.252), of this operating permit. Material sampling must be conducted in accordance with protocols approved by the Director. All performance test results shall be based on the arithmetic average of three valid runs. (NAC 445B.252(5))~~

~~b. Testing shall be conducted on the exhaust stack of **S2.064 and S2.065**.~~

~~c. Method 5 in Appendix A of 40 CFR Part 60 shall be used to determine PM emissions. The sample volume for each test run shall be at least 1.7 dscm (60 dscf). Test runs must be conducted for up to two hours in an effort to collect this minimum sample.~~

~~d. Method 201A and Method 202 in Appendix M of 40 CFR Part 51 shall be used to determine~~ ~~PM_{10}~~ ~~and~~ ~~$PM_{2.5}$~~ ~~emissions. The sample time and sample volume collected for each test run shall be sufficient to collect enough mass to weigh accurately.~~

~~e. The Method 201A and 202 test required in this section may be replaced by a Method 5 in Appendix A of 40 CFR Part 60 and Method 202 in Appendix M of 40 CFR Part 51 test. All particulate captured in the Method 5 and Method 202 test performed under this provision shall be considered~~ ~~$PM_{2.5}$~~ ~~for determination of compliance.~~

~~f. Method 7E in Appendix A of 40 CFR Part 60 shall be used to determine the nitrogen oxides concentration. Each test will be run for a minimum of one hour.~~

~~g. Method 8 in Appendix A of 40 CFR Part 60 shall be used to determine the Sulfuric Acid Mist concentration. The Method 8 test required in this section may be replaced by a combination of Conditional Test Method (CTM) 013, CTM-013A, and CTM-013B tests. Each test will be run for a minimum of one hour.~~

~~h. Method 9 in Appendix A of 40 CFR Part 60 shall be used to determine opacity. Opacity observations shall be conducted concurrently with the applicable performance test. The minimum total time of observations shall be six minutes (24 consecutive observations recorded at 15 second intervals), unless otherwise specified by an applicable subpart.~~

~~i. Method 10 in Appendix A of 40 CFR Part 60 shall be used to determine the carbon monoxide concentration. Each test will be run for a minimum of one hour.~~

Section IV. Specific Operating Conditions (continued)

L. Emission Units S2.064 and S2.065 (continued)

~~5. Performance and Compliance Testing (NAC 445B.3405, (NAC 445B.252(1)) (continued)~~
~~The Permittee, upon issuance of this operating permit, shall conduct and record renewal performance testing at least 90 days prior to the expiration of this operating permit, but no earlier than 365 days from the date of expiration of this operating permit, and every 5 years thereafter, in accordance with the following:~~

~~j. Method 25A in Appendix A of 40 CFR Part 60 shall be used to determine the volatile organic compound concentration. Method 18 in Appendix A of 40 CFR Part 60 or Method 320 in Appendix A of CFR Part 63 may be used in conjunction with Method 25A to break out the organic compounds that are not considered VOC's by definition per 40 CFR 51.100(s). Each Method 25A test will be run for a minimum of one hour.~~

~~k. The performance tests required in **L.5.c.** through **L.5.j.** of this section shall be conducted at the best achievable heat input rate at normal operating conditions, unless otherwise approved pursuant to NAC 445B.252.~~

~~l. The Permittee shall record the quantity of **Pipeline Quality Natural Gas** combusted (in standard cubic feet or hundreds of standard cubic feet) for each test run and the heat content (in Btu/scf) for each performance test event.~~

~~m. Using the most recent performance tests, as specified above, the Permittee shall calculate the following emission factors, based on the average of 3 test runs:~~

~~(1) Pounds of PM per scf (lbs PM/scf) of Pipeline Quality Natural Gas, or pounds of PM per MMBtu (lbs PM/MMBtu) of Pipeline Quality Natural Gas.~~

~~(2) Pounds of PM_{10} per scf (lbs PM_{10}/scf) of Pipeline Quality Natural Gas, or pounds of PM_{10} per MMBtu (lbs PM_{10}/MMBtu) of Pipeline Quality Natural Gas.~~

~~(3) Pounds of $PM_{2.5}$ per scf (lbs $PM_{2.5}$/scf) of Pipeline Quality Natural Gas, or pounds of $PM_{2.5}$ per MMBtu (lbs PM_{10}/MMBtu) of Pipeline Quality Natural Gas.~~

~~(4) Pounds of NO_X per scf (lbs NO_X/scf) of Pipeline Quality Natural Gas, or pounds of NO_X per MMBtu (lbs NO_X/MMBtu) of Pipeline Quality Natural Gas.~~

~~(5) Pounds of CO per scf (lbs CO/scf) of Pipeline Quality Natural Gas, or pounds of CO per MMBtu (lbs CO/MMBtu) of Pipeline Quality Natural Gas.~~

~~(6) Pounds of VOC per scf (lbs VOC/scf) of Pipeline Quality Natural Gas, or pounds of VOC per MMBtu (lbs VOC/MMBtu) of Pipeline Quality Natural Gas.~~

~~6. Federal Requirements~~

~~a. Standards of Performance for New Stationary Sources – 40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines~~

~~(1) Emission Limits for Nitrogen Oxides (40 CFR 60.4320, Table 1)~~
~~For a new, modified, or reconstructed turbine firing natural gas with a heat input at peak load greater than 850 MMBtu per hour, the Permittee shall meet the NO_X emission standard of **15** parts per million (ppm) at 15 percent O_2 (101.8 lb/hr) or **52** nanograms per Joule (ng/J) of useful output (0.43 pounds per megawatt-hour (lb/MWh)). (40 CFR 60.4320(a) and (b))~~

~~(2) Emission Limits for Sulfur Dioxide (40 CFR 60.4330)~~
~~The Permittee shall comply with one of the following (40 CFR 60.4430(a)):~~

~~(a) Not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of **110** ng/J (0.90 lb/MWh gross output or 228.6 lb/hr) (40 CFR 60.4430(a)(1)); or~~

~~(b) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, the Permittee must not cause to be discharged into the atmosphere from the affected source any gases that contain SO_2 in excess of **65** ng SO_2/J (0.15 lb SO_2/MMBtu) heat input. (40 CFR 60.4430(a)(3))~~

Section IV. Specific Operating Conditions (continued)

M. Emission Units S2.066 and S2.067

System 33 – Combined Cycle Combustion Turbine Circuit No. 9 – Pipeline Quality Natural Gas – 254 MW Nominal Output		Location UTM (Zone 11, NAD 83)	
		m North	m East
S2.066	Combined Cycle Combustion Turbine #9 (Manufactured by General Electric; Serial CT9-298614; Date 2007; Maximum Heat Input Rate 1,862.0 MMBtu/hr)	4,382,090	283,144
S2.067	Duct Burner #9 (Manufactured by Nooter; Serial DB-22896B; Date 2007; Maximum Heat Input Rate 660.0 MMBtu/hr) & Heat Recovery Steam Generator #9 (Manufactured by General Electric; Serial HRSG9-CP28-09-01; Date 2007)	4,382,090	283,144

1. Air Pollution Control Equipment (NAC 445B.3405)
   a. NO_X emissions from **S2.066 and S2.067** shall be controlled by a **Selective Catalytic Reduction (SCR)**. The SCR shall utilize Ammonia Injection into the SCR at a volume specified by the manufacturer.
   b. CO and VOC emissions from **S2.066 and S2.067** shall be controlled by an **Oxidation Catalyst** for control.
   ~~c. Emissions from **S2.066 and S2.067** are discharged through the same exhaust stack.~~
   ~~d. Descriptive Stack Parameters~~
   ~~Stack Height: 150.0 feet~~
   ~~Stack Diameter: 18.0 feet~~
   ~~Stack Temperature: 173 °F~~
   ~~Exhaust Flow: 960,000 dry standard cubic feet per minute (dscfm)~~

~~2. Operating Parameters (NAC 445B.3405)~~
   ~~a. **S2.066 and S2.067** may consume only **Pipeline Quality Natural Gas**.~~
   ~~b. The maximum allowable heat input rate for **S2.066 and S2.067**, combined, shall not exceed **2,522.0 million Btu (MMBtu)** per any one-hour period.~~
   ~~c. The maximum allowable fuel consumption rate for **S2.066 and S2.067**, combined, shall not exceed **2,475,000.0 standard cubic feet (scf)** per any one-hour period.~~
   ~~d. Hours~~
   ~~(1) **S2.066 and S2.067**, each, may operate a total of **24** hours per day.~~

3. Emission Limits (NAC 445B.305, NAC 445B.3405)
   The Permittee, upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from the exhaust stack of **S2.066 and S2.067** the following pollutants in excess of the following specified limits:
   ~~a. The discharge of **PM** (particulate matter) to the atmosphere shall not exceed **25.0** pounds per hour, nor more than **109.5** tons per 12-month rolling period.~~
   ~~b. The discharge of **PM_{10}** (particulate matter less than or equal to 10 microns in diameter) to the atmosphere shall not exceed **25.0** pounds per hour, nor more than **109.5** tons per 12-month rolling period.~~
   ~~c. BACT Emission Limit – The discharge of **PM_{10}** to the atmosphere shall not exceed **0.011** pounds per million Btu (MMBtu), filterable and condensable, per 3-hour rolling period.~~
   ~~d. The discharge of **$PM_{2.5}$** (particulate matter less than or equal to 2.5 microns in diameter) to the atmosphere shall not exceed **25.0** pounds per hour, nor more than **109.5** tons per 12-month rolling period.~~
   ~~e. The discharge of **SO_2** (sulfur dioxide) to the atmosphere shall not exceed **2.0** pound per hour, nor more than **8.76** tons per 12-month rolling period.~~
   ~~f. The discharge of **NO_X** (oxides of nitrogen) to the atmosphere shall not exceed **20.0** pounds per hour (based on a 3-hour rolling period), nor more than **87.6** tons per 12-month rolling period.~~
   g. BACT Emission Limit – The discharge of **NO_X** to the atmosphere shall not exceed **2.00** parts per million (ppmv) by volume at 15 percent oxygen and on a dry basis, per 3-hour rolling period.
   ~~h. The discharge of **CO** (carbon monoxide) to the atmosphere shall not exceed **12.0** pounds per hour, nor more than **52.6** tons per 12-month rolling period.~~
   ~~i. BACT Emission Limit – The discharge of **CO** to the atmosphere shall not exceed **3.50** ppmv by volume at 15 percent oxygen and on a dry basis, per 3-hour rolling period.~~

Section IV. Specific Operating Conditions (continued)

M. Emission Units S2.066 and S2.067 (continued)

3. Emission Limits (NAC 445B.305, NAC 445B.3405) (continued)
The Permittee, upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from the exhaust stack of **S2.066 and S2.067** the following pollutants in excess of the following specified limits:
~~j. The discharge of **VOCs** (volatile organic compounds) to the atmosphere shall not exceed **7.5** pounds per hour, nor more than **32.9** tons per 12-month rolling period.~~
~~k. BACT Emission Limit – The discharge of **VOCs** to the atmosphere shall not exceed **4.00** ppmv by volume at 15 percent oxygen and on a dry basis, per 3-hour rolling period.~~
~~l. The discharge of **Sulfuric Acid Mist** to the atmosphere shall not exceed **1.00** pounds per hour, nor more than **4.40** tons per 12-month rolling period.~~
~~m. NAC 445B.22017 – The opacity from the exhaust stack of **S2.066 and S2.067** shall not equal or exceed **20** percent.~~
~~n. NAC 445B.2203 – The maximum allowable discharge of **PM**~~$\cancel{_{10}}$~~ to the atmosphere from the exhaust **S2.066 and S2.067** shall not exceed **0.17** pounds per MMBtu.~~

~~4. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405)~~
~~The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.~~
~~a. Monitor and record the hours of operation for **S2.066 and S2.067** on a daily basis.~~
~~b. Calibrate, operate, and maintain a fuel flow meter to continuously measure the volume of **Pipeline Quality Natural Gas** consumed in **S2.066 and S2.067** (in standard cubic feet or hundreds of standard cubic feet). The fuel flow meter shall be installed at an appropriate location in the fuel delivery system to accurately and continuously measure the fuel consumed in **S2.066 and S2.067** in accordance with the requirements prescribed in 40 CFR Part 75.~~
~~c. Calibrate, operate, and maintain a Continuous Data Collection System (CDCS) to continuously record the quantity (in standard cubic feet or hundreds of standard cubic feet) of **Pipeline Quality Natural Gas** as measured by the fuel flow meter required under **M.5.b.** of this section. The CDCS will be installed, calibrated, operated and maintained in accordance with the manufacturer's specifications and requirements prescribed in 40 CFR Part 75.~~
~~d. Missing GCV or fuel flow data may be substituted as prescribed in 40 CFR Part 75, Appendix D.~~
~~e. Monitor and record the heat content of the **Pipeline Quality Natural Gas** combusted (in Btu per standard cubic feet). The heat content of the **Pipeline Quality Natural Gas** will be based on the supplier's data and specifications.~~
~~f. The hourly heat input of the **Pipeline Quality Natural Gas** (in MMBtu/hr) combusted will be calculated from the hourly fuel usage recorded in **M.5.c.** of this section.~~

~~**Sample Calculation:**~~

~~**(scf Natural Gas/hr)(Btu/scf) = Btu/hr or MMBtu/hr**~~

~~g. The hourly emission rate of PM, PM~~$\cancel{_{10}}$~~, PM~~$\cancel{_{2.5}}$~~, VOC, and Sulfuric Acid Mist, each, in pounds per hour (lbs/hr) will be calculated from the hourly quantity of **Pipeline Quality Natural Gas** combusted determined in **M.5.c.** of this section, and the emission factor derived in **M.6.m.** of this section.~~

~~**Sample Calculation:**~~

~~**(scf/hr)(lbs pollutant/scf) = lbs pollutant/hr**~~

~~**or**~~

~~**(MMBtu/hr)(lbs pollutant/MMBtu) = lbs pollutant/hr**~~

Section IV. Specific Operating Conditions (continued)

M. Emission Units S2.066 and S2.067 (continued)

~~4. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405) (continued)~~
~~The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.~~

~~h. The hourly emission rate of PM, PM_{10}, $PM_{2.5}$, VOC, and Sulfuric Acid Mist, each in pounds per MMBtu (lbs/MMbtu) will be calculated from the heat content of the fuel determined in **M.5.c.** of this section, and the emission factor derived in **M.6.m.** of this section.~~

~~**Sample Calculation:**~~

~~**(scf/Btu)(lb pollutant/scf) = lbs pollutant/Btu or lbs pollutant/MMBtu**~~

~~i. Calculate annually the SO_2 emissions in tons based on quantity of **Pipeline Quality Natural Gas** determined in **M.5.c.** of this section and sulfur in units of grains per dry standard cubic feet of **Pipeline Quality Natural Gas** from the SO_2 emission factor for **Pipeline Quality Natural Gas** combusted from 40 CFR Part 75 Appendix D.~~

~~5. Performance and Compliance Testing (NAC 445B.3405, (NAC 445B.252(1))~~
~~The Permittee, upon issuance of this operating permit, shall conduct and record renewal performance testing at least 90 days prior to the expiration of this operating permit, but no earlier than 365 days from the date of expiration of this operating permit, and every 5 years thereafter, in accordance with the following:~~

~~a. All opacity compliance demonstrations and performance tests must comply with the advance notification, protocol review, operational conditions, reporting, and other requirements of Section **I.I.**, Testing and Sampling (NAC 445B.252), of this operating permit. Material sampling must be conducted in accordance with protocols approved by the Director. All performance test results shall be based on the arithmetic average of three valid runs. (NAC 445B.252(5))~~
~~b. Testing shall be conducted on the exhaust stack of **S2.066 and S2.067**.~~
~~c. Method 5 in Appendix A of 40 CFR Part 60 shall be used to determine PM emissions. The sample volume for each test run shall be at least 1.7 dscm (60 dscf). Test runs must be conducted for up to two hours in an effort to collect this minimum sample.~~
~~d. Method 201A and Method 202 in Appendix M of 40 CFR Part 51 shall be used to determine PM_{10} and $PM_{2.5}$ emissions. The sample time and sample volume collected for each test run shall be sufficient to collect enough mass to weigh accurately.~~
~~e. The Method 201A and 202 test required in this section may be replaced by a Method 5 in Appendix A of 40 CFR Part 60 and Method 202 in Appendix M of 40 CFR Part 51 test. All particulate captured in the Method 5 and Method 202 test performed under this provision shall be considered $PM_{2.5}$ for determination of compliance.~~
~~f. Method 7E in Appendix A of 40 CFR Part 60 shall be used to determine the nitrogen oxides concentration. Each test will be run for a minimum of one hour.~~
~~g. Method 8 in Appendix A of 40 CFR Part 60 shall be used to determine the Sulfuric Acid Mist concentration. The Method 8 test required in this section may be replaced by a combination of Conditional Test Method (CTM)-013, CTM-013A, and CTM-013B tests. Each test will be run for a minimum of one hour.~~
~~h. Method 9 in Appendix A of 40 CFR Part 60 shall be used to determine opacity. Opacity observations shall be conducted concurrently with the applicable performance test. The minimum total time of observations shall be six minutes (24 consecutive observations recorded at 15-second intervals), unless otherwise specified by an applicable subpart.~~
~~i. Method 10 in Appendix A of 40 CFR Part 60 shall be used to determine the carbon monoxide concentration. Each test will be run for a minimum of one hour.~~

Section IV. Specific Operating Conditions (continued)

M. Emission Units S2.066 and S2.067 (continued)

~~5. Performance and Compliance Testing (NAC 445B.3405, (NAC 445B.252(1)) (continued)~~
~~The Permittee, upon issuance of this operating permit, shall conduct and record renewal performance testing at least 90 days prior to the expiration of this operating permit, but no earlier than 365 days from the date of expiration of this operating permit, and every 5 years thereafter, in accordance with the following:~~

~~j. Method 25A in Appendix A of 40 CFR Part 60 shall be used to determine the volatile organic compound concentration. Method 18 in Appendix A of 40 CFR Part 60 or Method 320 in Appendix A of CFR Part 63 may be used in conjunction with Method 25A to break out the organic compounds that are not considered VOC's by definition per 40 CFR 51.100(s). Each Method 25A test will be run for a minimum of one hour.~~

~~k. The performance tests required in **M.5.c.** through **M.5.j.** of this section shall be conducted at the best achievable heat input rate at normal operating conditions, unless otherwise approved pursuant to NAC 445B.252.~~

~~l. The Permittee shall record the quantity of **Pipeline Quality Natural Gas** combusted (in standard cubic feet or hundreds of standard cubic feet) for each test run and the heat content (in Btu/scf) for each performance test event.~~

~~m. Using the most recent performance tests, as specified above, the Permittee shall calculate the following emission factors, based on the average of 3 test runs:~~

~~(1) Pounds of PM per scf (lbs PM/scf) of Pipeline Quality Natural Gas, or pounds of PM per MMBtu (lbs PM/MMBtu) of Pipeline Quality Natural Gas.~~

~~(2) Pounds of PM_{10} per scf (lbs PM_{10}/scf) of Pipeline Quality Natural Gas, or pounds of PM_{10} per MMBtu (lbs PM_{10}/MMBtu) of Pipeline Quality Natural Gas.~~

~~(3) Pounds of $PM_{2.5}$ per scf (lbs $PM_{2.5}$/scf) of Pipeline Quality Natural Gas, or pounds of $PM_{2.5}$ per MMBtu (lbs PM_{10}/MMBtu) of Pipeline Quality Natural Gas.~~

~~(4) Pounds of NO_X per scf (lbs NO_X/scf) of Pipeline Quality Natural Gas, or pounds of NO_X per MMBtu (lbs NO_X/MMBtu) of Pipeline Quality Natural Gas.~~

~~(5) Pounds of CO per scf (lbs CO/scf) of Pipeline Quality Natural Gas, or pounds of CO per MMBtu (lbs CO/MMBtu) of Pipeline Quality Natural Gas.~~

~~(6) Pounds of VOC per scf (lbs VOC/scf) of Pipeline Quality Natural Gas, or pounds of VOC per MMBtu (lbs VOC/MMBtu) of Pipeline Quality Natural Gas.~~

~~6. Federal Requirements~~

~~a. Standards of Performance for New Stationary Sources – 40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines~~

~~(1) Emission Limits for Nitrogen Oxides (40 CFR 60.4320, Table 1)~~
~~For a new, modified, or reconstructed turbine firing natural gas with a heat input at peak load greater than 850 MMBtu per hour, the Permittee shall meet the NO_X emission standard of **15** parts per million (ppm) at 15 percent O_2 (101.8 lb/hr) or **52** nanograms per Joule (ng/J) of useful output (0.43 pounds per megawatt-hour (lb/MWh)). (40 CFR 60.4320(a) and (b))~~

~~(2) Emission Limits for Sulfur Dioxide (40 CFR 60.4330)~~
~~The Permittee shall comply with one of the following (40 CFR 60.4430(a)):~~

~~(a) Not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of **110** ng/J (0.90 lb/MWh gross output or 228.6 lb/hr) (40 CFR 60.4430(a)(1)); or~~

~~(b) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis, as determined based on total heat input, the Permittee must not cause to be discharged into the atmosphere from the affected source any gases that contain SO_2 in excess of **65** ng SO_2/J (0.15 lb SO_2/MMBtu) heat input. (40 CFR 60.4430(a)(3))~~

Section V. Continuous Emissions Monitoring System (CEMS) Conditions

A. 40 CFR Part 60 Appendix B and Appendix F – Oxides of Nitrogen (NO_X) Continuous Emissions Monitoring System (CEMS) Requirements for System 03A (S2.003), Systems 05A/05C (S2.006), System 06A/06C (S2.007), System 07C (S2.009/S2.009.1), System 32 (S2.064/S2.065), and System 33 (S2.066/S2.067) (NAC 445B.3405)

1. On or before the date of start-up of **S2.003, S2.006, S2.007, S2.009/S2.009.1, S2.064/S2.065, and S2.066/S2.067**, each, the Permittee shall install, calibrate, operate, and maintain a NO_X CEMS in the exhaust stacks of **S2.003, S2.006, S2.007, S2.009/S2.009.1, S2.064/S2.065, and S2.066/S2.067**, each. The CEMS sampling probe must be installed at an appropriate location in the exhaust stacks to accurately and continuously measure the concentration of NO_X (in ppmv) from **S2.003, S2.006, S2.007, S2.009/S2.009.1, S2.064/S2.065, and S2.066/S2.067**, each, in accordance with the requirements prescribed in Nevada Administrative Code (NAC) 445B.252 to NAC 445B.267, applicable subparts 40 CFR Part 75 Appendix A and Appendix B. Verification of the operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the devices.

2. The Permittee shall conduct the following performance specifications (40 CFR Part 75 Appendix A Section 3.0):
   a. Calibration Error (40 CFR Part 75 Appendix A Section 3.1):
   The calibration error of the NO_X pollutant concentration monitor shall not deviate from the reference value of either the zero or upscale calibration gas by more than 2.5 percent of the span of the instrument. Alternatively, where the span value is less than 200 ppm, calibration error test results are also acceptable if the absolute value of the difference between the monitor response value and the reference value is less than or equal to 5 ppm.
   b. Linearity Check (40 CFR part 75 Appendix A 3.2)
   For the NO_X pollutant concentration monitor, the error in linearity for each calibration gas concentration shall not exceed or deviate from the reference value by more than 5.0 percent. Linearity check results are also acceptable if the absolute value of the difference between the average of the monitor response values and the average of the reference values is less than or equal to 5 ppm.
   c. Relative Accuracy (40 CFR Part 75 Appendix A Section 3.3):
   Relative Accuracy for NO_X-Diluent Continuous Emission Monitoring Systems:
      (1) The relative accuracy for NO_X-diluent continuous emission monitoring systems shall not exceed 10.0 percent.
      (2) For affected units where the average of the reference method measurements of NO_X emission rate during the relative accuracy test audit is less than or equal to 0.200 lb/mmBtu, the difference between the mean value of the continuous emission monitoring system measurements and the reference method mean value shall not exceed ±0.020 lb/mmBtu, wherever the relative accuracy specification of 10.0 percent is not achieved.
   d. Bias (40 CFR Part 75 Appendix A Section 3.4):
   NO_X Concentration Monitoring Systems and NO_X-Diluent Continuous Emission Monitoring Systems:
      (1) NO_X-diluent continuous emission monitoring systems and NO_X concentration monitoring systems used to determine NO_X mass emissions shall not be biased low.
   e. Cycle Time (40 CFR Part 75 Appendix A Section 3.5):
   The cycle time for pollutant concentration monitors, oxygen monitors used to determine percent moisture, and any other monitoring component of a continuous emission monitoring system that is required to perform a cycle time test shall not exceed 15 minutes.

3. Data Acquisition and Handling Systems shall (40 CFR Part 75 Appendix A Sections 4(a), 4(b), 4(c)):
   a. Read and record the full range of pollutant concentrations, volumetric flow, and fuel flowrate through the upper range value;
   b. Calculate and record intermediate values necessary to obtain emissions, such as mass fuel flowrate and heat input rate;
   c. Interpret and convert the individual output signals from all applicable monitoring systems to produce a continuous readout of pollutant emission rates or pollutant mass emissions in the appropriate units;
   d. Predict and record NO_X emission rate using the heat input rate and the NO_X/heat input correlation;
   e. Monitor calibration error; any bias adjustments to pollutant emission rates or pollutant mass emissions data;
   f. Calculate and record all missing data substitution values; and
   g. Provide a continuous, permanent record of all measurements and required information in an electronic format.

Section V. Continuous Emissions Monitoring System (CEMS) Conditions (continued)

A. 40 CFR Part 60 Appendix B and Appendix F – NO_X CEMS Requirements for System 03A (S2.003), Systems 05A/05C (S2.006), System 06A/06C (S2.007), System 07C (S2.009/S2.009.1), System 32 (S2.064/S2.065), and System 33 (S2.066/S2.067) (NAC 445B.3405) (continued)

4. The Permittee shall comply with the following certification tests and procedures (40 CFR Part 75 Appendix A Section 6.0):
   a. Linearity Check
   b. 7-Day Calibration Test
   c. Cycle Time Test
   d. Relative Accuracy and Bias Tests

5. The Permittee shall develop and implement a quality assurance/quality control (QA/QC) program for the continuous emission monitoring systems and alternative monitoring systems under 40 CFR Part 75 Subpart E and their components. (40 CFR Part 75 Appendix B Section 1.0)

6. The Permittee shall comply with the following monitoring system requirements (40 CFR Part 75 Appendix B Section 1.1):
   a. Preventative Maintenance (40 CFR Part 75 Appendix B Section 1.1.1):
   The Permittee shall keep a written record of procedures needed to maintain the monitoring system in proper operating condition and a schedule for those procedures.
   b. Recordkeeping and Reporting (40 CFR Part 75 Appendix B Section 1.1.2):
   The Permittee shall keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements in the applicable subparts.
   c. Maintenance Records (40 CFR Part 75 Appendix B Section 1.1.3):
   The Permittee shall keep a record of all testing, maintenance, or repair activities performed on any monitoring system or component in a location and format suitable for inspection. A maintenance log may be used for this purpose. Additionally, any adjustment that recharacterizes a system's ability to record and report emissions data must be recorded, and a written explanation of the procedures used to make the adjustment(s) shall be kept.

7. The Permittee shall comply with the following specific requirements for CEMS (40 CFR Part 75 Appendix B Section 1.2):
   a. Calibration Error Test and Linearity Check Procedures (40 CFR Part 75 Appendix B Section 1.2.1):
   The Permittee shall keep a written record of the procedures used for daily calibration error tests and linearity checks and identify any calibration error test and linearity check procedures specific to the continuous emission monitoring system that vary from the applicable procedures.
   b. Calibration and Linearity Adjustments (40 CFR Part 75 Appendix B Section 1.2.2):
   The Permittee shall explain how each component of the CEMS will be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. The Permittee shall identify equations, conversion factors and other factors affecting calibration of each CEMS.
   c. Relative Accuracy Test Audit Procedures (40 CFR Part 75 Appendix B Section 1.2.3):
   The Permittee shall keep a written record of procedures and details peculiar to the installed continuous emission monitoring systems that are to be used for relative accuracy test audits, such as sampling and analysis methods.
   d. Parametric Monitoring for Units With Add-on Emission Controls (40 CFR Part 75 Appendix B Section 1.2.4):
   The Permittee shall keep a written (or electronic) record including a list of operating parameters for the add-on SO_2 or NO_X emission controls, and the range of each operating parameter that indicates the add-on emission controls are operating properly. The Permittee shall keep a written (or electronic) record of the parametric monitoring data during each NO_X missing data period.

Section V. Continuous Emissions Monitoring System (CEMS) Conditions (continued)

A. 40 CFR Part 60 Appendix B and Appendix F – NO_X CEMS Requirements for System 03A (S2.003), Systems 05A/05C (S2.006), System 06A/06C (S2.007), System 07C (S2.009/S2.009.1), System 32 (S2.064/S2.065), and System 33 (S2.066/S2.067) (NAC 445B.3405) (continued)

8. The Permittee shall conduct quality assurance testing at the required frequencies as described by the following (40 CFR Part 75 Appendix B Section 2.0):
   a. Daily Assessments
      (1) Calibration Error Test
         (a) On-line Daily Calibration Error Tests
         (b) Off-line Daily Calibration Error Tests
      (2) Daily Flow Interference Check
      (3) Additional Calibration Error Tests and Calibration Adjustments
   b. Quarterly Assessments
      (1) Linearity Check
      (2) Leak Check
      (3) Flow-to-Load Ratio or Gross Heat Rate Evaluation
   c. Semiannual and Annual Assessments
      (1) Relative Accuracy Test Audit (RATA)
         (a) The Permittee shall perform relative accuracy test audits semiannually for each applicable primary and redundant backup monitor. No more than eight successive calendar quarters shall elapse after the quarter in which a RATA was last performed without a subsequent RATA having been conducted.
         (b) Relative accuracy test audits of applicable primary and redundant backup monitors may be performed annually if any of the conditions under 40 CFR Part 75 Appendix B Sections 2.3.1.2(a) through 2.3.1.2(i) are met for the specific monitoring system involved.
         (c) Annual 2-load flow RATA or annual 3-load flow RATA.

9. The Permittee shall ensure RATA data validation by conducting the following (40 CFR Part 75 Appendix B Section 2.3.2):
   a. A RATA shall not commence if the monitoring system is operating out-of-control with respect to any of the daily and quarterly quality assurance or with respect to the additional calibration error tests.
   b. The RATA may be done with no corrective maintenance, repair, calibration adjustments, re-linearization or reprogramming of the monitoring system prior to the test.
   c. The RATA may be done after performing only the routine or non-routine calibration adjustments but no other corrective maintenance, repair, re-linearization or reprogramming of the monitoring system. Trial RATA runs may be performed after the calibration adjustments and additional adjustments may be made prior to the RATA, as necessary, to optimize the performance of the CEMS. The trial RATA runs need not be reported.
   d. The RATA may be done after repair, corrective maintenance, re-linearization or reprogramming of the monitoring system.
   e. Once a RATA is commenced, the test must be done hands-off. No adjustment of the monitor's calibration is permitted during the RATA test period, other than the routine calibration adjustments following daily calibration error tests. If a routine daily calibration error test is performed and passed just prior to a RATA (or during a RATA test period) and a mathematical correction factor is automatically applied by the DAHS, the correction factor shall be applied to all subsequent data recorded by the monitor, including the RATA test data. For 2-level and 3-level flow monitor audits, no linearization or reprogramming of the monitor is permitted in between load levels.
   f. For each monitoring system, report the results of all completed and partial RATAs that affect data validation in the quarterly report. A record of all RATAs, trial RATA runs and RATA attempts (whether reported or not) must be kept on-site as part of the official test log for each monitoring system.

10. If an applicable monitor fails the bias test, the Permittee shall use a bias adjustment factor (BAF) or the allowable alternative BAF to adjust the monitored data. (40 CFR Part 75 Appendix B Section 2.3.4)

Section V. Continuous Emissions Monitoring System (CEMS) Conditions (continued)

~~**B. 40 CFR Part 60 Appendix B and Appendix F – Carbon Monoxide (CO) CEMS Requirements for Systems 05A/05C (S2.006), System 06A/06C (S2.007), System 32 (S2.064/S2.065), and System 33 (S2.066/S2.067) (NAC 445B.3405)**~~

~~1. On or before the date of start-up of **S2.006, S2.007, S2.064/S2.065, and S2.066/S2.067**, each, the Permittee shall install, calibrate, operate, and maintain a CO CEMS in the exhaust stacks of **S2.006, S2.007, S2.064/S2.065, and S2.066/S2.067**, each. The CEMS sampling probe must be installed at an appropriate location in the exhaust stacks to accurately and continuously measure the concentration of CO (in ppmv) from **S2.006, S2.007, S2.064/S2.065, and S2.066/S2.067**, each,, in accordance with the requirements prescribed in Nevada Administrative Code (NAC) 445B.252 to NAC 445B.267, applicable subparts 40 CFR Part 60 Appendix B and Appendix F. Verification of the operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the devices.~~

~~2. The Permittee shall perform procedures for the following (40 CFR Part 60 Appendix B PS-4A Sections 8.3 through 8.4):~~
   ~~a. Response Time Test~~
   ~~b. Interference Check~~

~~3. The Permittee shall comply with the following method performance specifications (40 CFR Part 60 Appendix B PS-4A Section 13.0):~~
   ~~a. Calibration Drift~~
   ~~b. Relative Accuracy~~
   ~~c. Response Time~~

~~4. The Permittee may perform alternative procedures as specified under 40 CFR Part 60 Appendix B PS-4A Section 16.0. (40 CFR Part 60 Appendix B PS-4A Section 16.0)~~

~~5. The Permittee shall develop and implement a Quality Control (QC) program. As a minimum, each QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities (40 CFR Part 60 Appendix F Procedure 1 Section 3.0):~~
   ~~a. Calibration of CEMS~~
   ~~b. Calibration maintenance of CEMS (including spare parts inventory)~~
   ~~c. Preventative maintenance of CEMS (including spare parts inventory)~~
   ~~d. Data recording, calculations, and reporting~~
   ~~e. Accuracy audit procedures including sampling and analysis methods~~
   ~~f. Program of corrective action for malfunctioning CEMS~~

~~6. The written procedures under **B.5.** of this section, must be kept on record and available for inspection by the Director. (40 CFR Part 60 Appendix F Procedure 1 Section 3.0)~~

~~7. The Permittee shall conduct a Calibration Drift Assessment according to 40 CFR Part 60 Appendix F Procedure 1 Sections 4.1 and 4.2. (40 CFR Part 60 Appendix F Procedure 1 Sections 4.1 and 4.2).~~

~~8. The Permittee shall record and report all CEMS data according to 40 CFR Part 60 Appendix F Procedure 1 Section 4.4. All measurements from the CEMS must be retained on file by the Permittee for at least 2 years. (40 CFR Part 60 Appendix F Procedure 1 Section 4.4)~~

~~9. Each CEMS must be audited at least once each calendar quarter. Successive quarterly audits shall occur no closer than 2 months. The audits shall be conducted as follows (40 CFR Part 60 Appendix F Procedure 1 Section 5.1):~~
   ~~a. The Relative Accuracy Test (RATA) shall be conducted once every four calendar quarters. (40 CFR Part 60 Appendix F Procedure 1 Section 5.1.1)~~
   ~~b. The Cylinder Gas Audit (CGA) shall be conducted every quarter except when a RATA is conducted. (40 CFR Part 60 Appendix F Procedure 1 Section 5.1.2)~~

Section V. Continuous Emissions Monitoring System (CEMS) Conditions (continued)

~~B. 40 CFR Part 60 Appendix B and Appendix F – CO CEMS Requirements for Systems 05A/05C (S2.006), System 06A/06C (S2.007), System 32 (S2.064/S2.065), and System 33 (S2.066/S2.067) (NAC 445B.3405) (continued)~~

~~10. Unless specified otherwise in the applicable subpart, the Permittee shall comply with the relative accuracy criteria:~~
   ~~a. For RATA (40 CFR Part 60 Appendix F Procedure 1 Section 5.2.3(1)):~~
      ~~(1) For CO emissions, RA shall be less than or equal to 10% (if the value determined by the Reference Method (RM) is greater than 50% of the emission limit) or RA shall be less than or equal to 5% (if the value determined by the RM is less than 50% of the emission limit). (40 CFR Part 60 Appendix B PS-4 Section 13.2)~~
   ~~b. For CGA ±15 percent of the average audit value for ±5 ppm, whichever is greater. (40 CFR Part 60 Appendix F Procedure 1 Section 5.2.3(2))~~

~~11. The Permittee shall conduct and report to the Director a quarterly audit as specified under 40 CFR Part 60 Appendix F Procedure 1 Section 7.0. (40 CFR Part 60 Appendix F Procedure 1 Section 7.0)~~

C. Monitoring Systems: Records; Reports (NAC 445B.265)

1. The Permittee subject to the provisions of NAC 445B.256 to 445B.267, inclusive, shall maintain records of the occurrence and duration of any start-up, shutdown or malfunction in the operation of an affected facility and any malfunction of the air pollution control equipment or any periods during which a continuous monitoring system or monitoring device is inoperative.
2. The Permittee required to install a continuous monitoring system shall submit a written report of excess emissions to the director for every calendar quarter. All quarterly reports must be postmarked by the 30th day following the end of each calendar quarter and must include the following information:
   a. The magnitude of excess emissions computed in accordance with NAC 445B.256 to 445B.267, inclusive, any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.
   b. Specific identification of each period of excess emissions that occurs during start-ups, shutdowns and malfunctions of the affected facility.
   c. The nature and cause of any malfunction, if known, the corrective action taken or preventative measures adopted.
   d. Specific identification of each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of any repairs or adjustments that were made.
      (1) When no excess emissions have occurred and the continuous monitoring system has not been inoperative, repaired or adjusted, such information shall be included in the report.
3. The Permittee subject to the provisions of NAC 445B.256 to 445B.267, inclusive, shall maintain a file of all measurements, including:
   a. Continuous monitoring systems, monitoring devices and performance testing measurements;
   b. All continuous monitoring system performance evaluations;
   c. All continuous monitoring systems or monitoring device calibration checks;
   d. Adjustments and maintenance performed on these systems or devices; and
   e. All other information required by NAC 445B.256 to 445B.267, inclusive, recorded in a permanent form suitable for inspection.
      (1) The file shall be retained for at least 2 years following the date of the measurements, maintenance, reports and records.

******End of Continuous Emissions Monitoring System (CEMS) Conditions******

Section VIII. Schedules of Compliance

~~A. 40 CFR Part 51.308, NAC 445B.305, NAC 445B.315, NAC 445B.3405~~
~~As part of Nevada's Regional Haze State Implementation Plan's (SIP) Long-Term Strategy to achieve reasonable progress, the Permittee shall shutdown and permanently cease operation of **System 07C (S2.009, S2.009.1)** no later than December 31, 2031.~~

******End of Schedule of Compliance ******

Appendix A.3 - Pilot Peak Plant, Graymont

Provisions provided in the following air quality operating permit issued by the Nevada Division of Environmental Protection for the Pilot Peak Plant are hereby incorporated and adopted into Nevada's Second Regional Haze SIP by reference. In this appendix, NDEP is only providing pages containing specific permit conditions relevant to this Regional Haze SIP. Provisions that are struck-out ~~are not~~ intended to be incorporated into the SIP by reference for approval or intended to be codified as part of Nevada's Second Regional Haze SIP.

NEVADA DIVISION OF
ENVIRONMENTAL PROTECTION

STATE OF NEVADA
Department of Conservation & Natural Resources

Joe Lombardo, *Governor*
James A. Settelmeyer, *Director*
Jennifer L. Carr, *Administrator*

June 14, 2024

Douglas Held
Plant Manager
Graymont Western US Inc.
P.O. Box 2520
Wendover, NV 89883

RE: Notification of Issuance of the Minor Revision of Class I Air Quality Operating Permit AP3274-1329.03, FIN A0367, Air Case 11821 – Pilot Peak Plant

Dear Mr. Held:

The Nevada Division of Environmental Protection – Bureau of Air Pollution Control (BAPC) has reviewed the application submitted by Graymont Western US Inc. on October 26, 2023 for the above-referenced operating permit under legal authority from Nevada Revised Statutes (NRS) 445B.100 through 445B.640, inclusive, and pursuant to regulations in Nevada Administrative Code (NAC) 445B.001 through 445B.3689, inclusive. Based upon technical review and recommendation, I hereby issue the operating permit with appropriate restrictions. Enclosed is your copy of the operating permit which must be posted conspicuously at the facility.

The draft copy of the above-referenced permit was submitted to EPA Region 9 on April 29, 2024 for the required 45-day review period pursuant to NAC 445B.3395 which defaults to end on June 13, 2024. EPA Region 9 had no further comments.

In accordance with NRS 445B.340 and NAC 445B.890, you may appeal the Department's issuance of the operating permit within 10 days after you receive the operating permit. Appeals may be filed with the State Environmental Commission located at 901 S. Stewart Street, Carson City, Nevada 89701. For questions regarding appeals, call (775) 687-9374.

Please review the operating permit carefully and ensure you understand all conditions, restrictions, monitoring, recordkeeping, and other requirements. If you have any questions, contact Derek Rizo at (775) 687-9495 or drizo@ndep.nv.gov.

Sincerely,

Jaimie Mara
Supervisor, Permitting Branch
Bureau of Air Pollution Control

JM/dr

Enclosure:	Class I Air Quality Operating Permit AP3274-1329.03
Certified Mail No.	9489 0090 0027 6498 7545 06
E-Copy (w/ enclosure):	Douglas Held, Graymont Western US Inc.
	Nate Stettler, Graymont Western US Inc.

Nevada Department of Conservation and Natural Resources • Division of Environmental Protection

Bureau of Air Pollution Control

901 SOUTH STEWART STREET SUITE 4001
CARSON CITY, NEVADA 89701-5249
p: 775-687-9349 • www.ndep.nv.gov/bapc

Facility ID No. A0367 *Permit No.* AP3274-1329.03

CLASS I AIR QUALITY OPERATING PERMIT (*40 CFR Part 70 Program)*

Issued to: GRAYMONT WESTERN US INC. – PILOT PEAK PLANT (HEREINAFTER REFERRED TO AS PERMITTEE)
Mailing Address: 3950 SOUTH 700 EAST, SUITE 301, SALT LAKE CITY, UTAH 84107
Driving Directions: 12 MILES NORTHWEST OF WENDOVER, NEVADA. TAKE I-80 WEST FROM WENDOVER FOR 11 MILES; TAKE EXIT 398 AND TURN LEFT ONTO PILOT RD; PROCEED FOR 3.5 MILES TO THE PILOT PEAK PLANT
General Facility Location:

SECTIONS 10, 12 – 16, 21 – 28, AND 34 – 36, T 34 N, R 68 E, MDB&M
SECTIONS 30 AND 31, T 34 N, R 69 E, MDB&M
HA 191 AND 187 – PILOT CREEK VALLEY AND GOSHUTE VALLEY / ELKO COUNTY
NORTH 4,522,759 M, EAST 731,468 M, UTM ZONE 11, NAD 83

Emission Unit List:

~~**A. System 01 – Limestone Truck Dump (Revised June 2024, Air Case # 11821)**~~

~~PF1.001~~	~~Limestone Truck Dump transfer to Primary Crusher Hopper~~
~~PF1.001.1~~	~~Conveyor C-2 Transfer to Crusher R-1~~

~~**B. System 01A – Limestone Truck Dump – Alternative Operating Scenario (Added June 2024, Air Case # 11821)**~~

~~PF1.001a~~	~~Limestone Truck Dump transfer to Primary Crusher Hopper~~

~~**C. System 02 – Primary Crushing and Screening Circuit (D-1)**~~

~~S2.001~~	~~Primary Crusher R-1 and Associated Transfers (IN from Primary Crusher Hopper; OUT to Conveyor C-1 (S2.002))~~
~~S2.004~~	~~Primary Screen S-1 and Associated Transfers (IN from Conveyor C-1 (S2.006); OUT to Conveyors C-2 (S2.005), C-3 (S2.009), C-7 (S2.008), and C-305 (S2.010))~~
~~S2.007~~	~~Conveyor C-306 to Conveyor C-3~~
~~S2.010.1~~	~~Conveyor C-7 Transfer to Conveyor C-4~~
~~S2.010.2~~	~~Hopper/Feeder F-1 Transfer to Conveyor C-1~~

~~**D. System 03 – Secondary Screening Circuit (D-311)**~~

~~S2.012~~	~~Secondary Screen and Associated Transfers (IN from Conveyor C-305 (S2.011); OUT to Conveyors C-5 (S2.014), C-306 (S2.013), and C-307 (S2.015))~~

~~**E. System 05 - Limestone Quarry Conveyance Transfers (Revised June 2024, Air Case # 11821)**~~

~~PF1.002~~	~~Conveyor C-3 Transfer to Stockpile~~
~~PF1.003~~	~~Conveyor C-4 Transfer to Stockpile~~
~~PF1.004~~	~~Conveyor C-5 Transfer to Conveyor C-6~~
~~PF1.005~~	~~Conveyor C-6 Transfer to Stockpile~~
~~PF1.006~~	~~Conveyor C-307 Transfer to Conveyor C-308~~
~~PF1.007~~	~~Conveyor C-308 Transfer to Stockpile~~

~~**F. System 05A - Limestone Quarry Conveyance Transfers – Alternative Operating Scenario (Added June 2024, Air Case # 11821)**~~

~~PF1.002a~~	~~Conveyor C-3 Transfer to Stockpile~~
~~PF1.003a~~	~~Conveyor C-4 Transfer to Stockpile~~
~~PF1.004a~~	~~Conveyor C-5 Transfer to Conveyor C-6~~
~~PF1.005a~~	~~Conveyor C-6 Transfer to Stockpile~~
~~PF1.006a~~	~~Conveyor C-307 Transfer to Conveyor C-308~~
~~PF1.007a~~	~~Conveyor C-308 Transfer to Stockpile~~

Emission Unit List (continued):

~~**G. System 06 - Lime Plant Conveyance Transfers**~~

~~PF1.008~~	~~Stockpile Transfer to Conveyor C-10 (F214)~~
~~PF1.009~~	~~Stockpile Transfer to Conveyor C-10 (F213)~~
~~PF1.010~~	~~Stockpile Transfer to Conveyor C-10 (F12)~~
~~PF1.011~~	~~Stockpile Transfer to Conveyor C-10 (F11)~~
~~PF1.012~~	~~Stockpile Transfer to Conveyor C-10 (F10)~~
~~PF1.013~~	~~Stockpile Transfer to Conveyor C-10 (F215)~~
~~PF1.014~~	~~Stockpile Transfer to Conveyor C-10 (F216)~~
~~PF1.015~~	~~Stockpile Transfer to Conveyor C-10 (F217)~~
~~PF1.016~~	~~Stockpile Transfer to Conveyor C-10 (F218)~~
~~PF1.017~~	~~Stockpile Transfer to Conveyor C-311 (F310)~~
~~PF1.018~~	~~Stockpile Transfer to Conveyor C-311 (F311)~~
~~PF1.019~~	~~Stockpile Transfer to Conveyor C-312 (F312)~~
~~PF1.020~~	~~Stockpile Transfer to Conveyor C-312 (F313)~~
~~PF1.021~~	~~Stockpile Transfer to Conveyor C-312 (F314)~~
~~PF1.022~~	~~Stockpile Transfer to Conveyor C-312 (F315)~~
~~PF1.023~~	~~Stockpile Transfer to Conveyor C-312 (F316)~~
~~PF1.024~~	~~Conveyor C-313 Transfer to Fines Stockpile~~
~~PF1.025~~	~~Conveyor C-11 Transfer to Fines Stockpile~~
~~PF1.026~~	~~Conveyor C-311 Transfer to Conveyor C-312~~

~~**H. System 07 - Lime Plant Stone Dressing Screen (Kilns 1 and 2) (D-10)**~~

~~S2.017~~	~~Stone Dressing Screen S-10 and Associated Transfers (IN from Conveyor C-10 (S2.016); OUT to Conveyor C-11 (S2.018) and C-12 (S2.019))~~

~~**I. System 08 - Lime Plant Stone Dressing Screen**~~

~~S2.021~~	~~Stone Dressing Screen S-312 and Associated Transfers (IN from Conveyor C-312 (S2.020); OUT to Conveyors C-313 (S2.022) and C-314 (S2.023))~~

~~**J. System 09 - Lime Plant Stone Surge Bins N-19 (Kiln 1) and N-219 (Kiln 2) (D-19)**~~

~~S2.024~~	~~Conveyor C-12 Transfer to Stone Surge Bins N-19 and N-219~~
~~S2.026~~	~~Stone Surge Bin N-19 (S2.025) Transfer to Conveyor C-19~~
~~S2.027~~	~~Conveyor C-19 transfer to Kin #1 Pre-heater PH-20~~
~~S2.029~~	~~Stone Surge Bin N-219 (S2.028) Transfer to Conveyor C-219~~
~~S2.030~~	~~Conveyor C-219 Transfer to Kiln #2 Pre-heater PH-220~~

K. System 10 - Kiln #1 Circuit (D-85) (Revised June 2024, Air Case # 11821)

S2.031	Kiln #1 Pre-heater PH-20
S2.032	Kiln #1 (K-20) and Associated Coal Mill R-92
S2.033	Kiln #1 Lime Cooler N-21

~~**L. System 11 - Kiln #1 Coal Handling Circuit**~~

~~PF1.027~~	~~Truck Dump to Coal Hopper N-90~~
~~PF1.028~~	~~Coal Hopper N-90 transfer to Conveyor C-90~~
~~PF1.029~~	~~Coal Silo T-90 Discharge to Conveyor C-92 (followed by fully enclosed transfer to Coal Mill R-92 (PF1.030))~~

~~**M. System 12 - #1 Coal Silo T-90 (D-91)**~~

~~S2.035~~	~~Conveyor C-90 Transfer to Coal Silo T-90~~

Issued to: GRAYMONT WESTERN US INC. – PILOT PEAK PLANT

Emission Unit List (continued):

N. System 13 - Kiln #2 Circuit (D-285) (Revised June 2024, Air Case # 11821)

S2.036	Kiln #2 Pre-heater PH-220
S2.037	Kiln #2 (K-220) and Associated Coal Mill R-292
S2.038	Kiln #2 Lime Cooler N-221

~~**O. System 13a - Kiln #2 Circuit (D-282)**~~

~~S2.037.1~~	~~Kiln #2 K-220 Cyclone Bin N-280~~

~~**P. System 14 - Kiln #2 Coal Handling Circuit**~~

~~PF1.031~~	~~Conveyor C-90 Transfer to Conveyor C-290~~
~~PF1.032~~	~~Coal Silo T-290 Discharge to Conveyor C-292 (followed by fully enclosed transfer to coal mill R-292 via Conveyor C-292 (PF1.033))~~

~~**Q. System 15 - Kiln #2 Coal Silo T-290 (D-291)**~~

~~S2.039~~	~~Conveyor C-290 Transfer to Coal Silo T-290~~

~~**R. System 16 - Lime Plant Stone Feed to Kiln #3 (D-382)**~~

~~S2.041~~	~~Kiln #3 Conveyor C-314 transfer to Pre-heater PH-321~~

S. System 17 - Kiln #3 Circuit (D-385) (Revised June 2024, Air Case # 11821)

S2.042	Kiln #3 Pre-heater PH-321
S2.043	Kiln #3 (K-321) and Associated Coal Mill R-392
S2.044	Kiln #3 Lime Cooler N-332

~~**T. System 18 - Kiln #3 Coal Handling Circuit**~~

~~PF1.034~~	~~Conveyor C-90 Transfer to Conveyor C-391~~
~~PF1.035~~	~~Coal Silo T-391 Discharge to Conveyor C-392 (followed by fully enclosed transfer to Coal Mill R-392 via conveyor C-392 (PF1.036))~~

~~**U. System 19 - Kiln #3 Coal Silo T-391**~~

~~S2.045~~	~~Conveyor C-391 transfer to Coal Silo T-391~~

Emission Unit List (continued):

~~V. System 20 - Product Lime Loadout from Kiln #1 D-82~~

~~S2.047~~	~~Kiln #1 Lime Cooler N-21 transfer to Conveyor C-30~~
~~S2.048~~	~~Conveyor C-30 Transfer to Bucket Elevator E-30~~
~~S2.051~~	~~Gate G-36 transfer to Kiln Run Silo T-40 (Silo T-40 Discharges via Fully Enclosed Transfer (S2.052))~~
~~S2.053~~	~~Feeder F-50 Transfer to Conveyor C-50~~
~~S2.054~~	~~Crusher R-50 and Associated Transfers (IN from Conveyor C-50; OUT to Gate G-55 (S2.055))~~
~~S2.056~~	~~Gate G-55 Transfer to Bucket Elevator E-30~~
~~S2.057~~	~~Gate G-36 Transfer to Core Bin N-30~~
~~S2.058~~	~~Core Bin N-30 Discharge~~
~~S2.067~~	~~Loadout Silo T-42 Discharge~~
~~S2.072~~	~~Conveyor C-231 Transfer to Bucket Elevator E-32~~
~~S2.074~~	~~Conveyor C-42 Transfer to Loadout Silo T-42~~
~~S2.075~~	~~Conveyor C-44 Transfer to Loadout Silo T-44 (Silo T-44 Discharges via Fully Enclosed Transfer Point to Conveyor C-61 (S2.109))~~
~~S2.077~~	~~Gate G-43 transfer to Kiln Run Silo T-40~~
~~S2.088~~	~~Gate G-39 Transfer to Kiln Run Silo T-40~~
~~S2.089~~	~~Gate G-39 Transfer to Core Bin N-30~~
~~S2.092~~	~~Gate G-37 Transfer to Core Bin N-30~~
~~S2.099~~	~~Gate G-44 Transfer to Kiln Run Silo T-40~~
~~S2.103~~	~~Conveyor C-51 Transfer to Conveyor C-50~~
~~S2.104~~	~~Gate G-55 Transfer to Bucket Elevator E-31~~
~~S2.106~~	~~Conveyor C-52 Discharge to Loadout~~
~~S2.108~~	~~Conveyor C-60 Discharge to Loadout~~
~~S2.110~~	~~Conveyor C-61 Discharge to Loadout~~
~~S2.111~~	~~Loadout Silo T-44 Discharge~~

~~W. System 21 - Product Lime Loadout from Kiln #2~~

~~S2.068~~	~~Kiln #2 Lime Cooler N-221 Transfer to Conveyor C-230~~
~~S2.069~~	~~Conveyor C-230 Transfer to Bucket Elevator E-230~~
~~S2.070~~	~~Mill R-250 and Associated Transfers (IN from Screen S-230 and Gate-236; OUT to Bucket Elevator E-230)~~
~~S2.071~~	~~Gate G-236 Transfer to Conveyor C-231~~
~~S2.078~~	~~Bucket Elevator E-230 Transfer to Gate G-235~~
~~S2.079~~	~~Gate G-235 Transfer to Screw Conveyor C-231~~
~~S2.080~~	~~Screen S-230 and Associated Transfers (IN from Gate G-235; OUT to Mill R-250, Gate G-236, and Conveyor C-231)~~

Issued to: GRAYMONT WESTERN US INC. – PILOT PEAK PLANT

Emission Unit List (continued):

~~**X. System 22 - Product Lime Loadout from Kiln #2 (DC-30)**~~

~~S2.050~~	~~Screen S-30 and Associated Transfers (IN from Gate G-36 and G-37 (S2.093); OUT to Conveyor C-42 or C-43 via Gate G-41 and Gate G-42 (S2.059); OUT to Conveyor C-42 or Screen S-30 Transfer to Kiln Run Silo T-40 (S2.062))~~
~~S2.060~~	~~Conveyor C-43 transfer to Silo T-43 (Silo T-43 Discharges via Fully Enclosed Transfer to Conveyor C-52 or Conveyor C-60 (S2.061 or S2.107))~~
~~S2.076~~	~~Conveyor C-41 Transfer to Kiln Run Silo T-41 (Silo T-41 Discharges Through Fully Enclosed Transfers to Either Conveyor C-51 or Conveyor C-52 (S2.102 or S2.105))~~
~~S2.081~~	~~Bucket Elevator E-32 Transfer to Gate G-38~~
~~S2.082~~	~~Screen S-31 and Associated Transfers (IN from Gate G-38 and Gate G-37 (S2.091); OUT to Screw Conveyor C-42 (S2.094), Gate G-44 (S2.096), and Gate G-43 (S2.100))~~
~~S2.083~~	~~Gate G-38 to Gate G-39~~
~~S2.084~~	~~Gate G-38 Transfer to Conveyor C-42~~
~~S2.085~~	~~Gate G-35 Transfer to Gate G-36 OR Gate G-35 Transfer to Screen S-31~~
~~S2.086~~	~~Bucket Elevator E-30 Transfer to Gate G-35~~
~~S2.087~~	~~Gate G-39 Transfer to Kiln Run Silo T-41~~
~~S2.090~~	~~Bucket Elevator E-31 Transfer to Gate G-37~~
~~S2.097~~	~~Gate G-44 Transfer to Screw Conveyor C-42 (Screw Conveyor C-42 Transfers to Conveyor C-44 via Fully Enclosed Transfer (S2.066))~~
~~S2.098~~	~~Gate G-44 Transfer to Conveyor C-43~~
~~S2.101~~	~~Gate-43 Transfer to Conveyor C-41~~

~~**Y. System 23 - Kiln #1 and Kiln #2 Cyclone/Baghouse Fines Silo Discharge**~~

~~PF1.038~~	~~Fine Dust Silo T-89 to Pugmill (includes discharge of saturated material from pugmill into truck (PF1.038.1))~~

~~**Z. System 24 - Kiln #1 and Kiln #2 Cyclone/Baghouse Product Loadout (D-89)**~~

~~S2.113~~	~~Process Baghouse Transfer to Fine Dust Silo T-89 via Conveyor C-285 and Conveyor C-85~~

~~**AA. System 25 - Kiln #1 and Kiln #2 Baghouse Fines Silo Discharge System (D-11)**~~

~~S2.224~~	~~Fines Silo T-89 Discharge to Truck via Retractable Spout~~

~~**AB. System 26 - Kiln #3 Baghouse Collection Product Loadout (D-388)**~~

~~S2.115~~	~~Process Baghouse Transfer to Fine Dust Silo T-388 via Conveyor C-385~~

~~**AC. System 27 - Kiln #3 Baghouse Fines Discharge System (D-389)**~~

~~S2.116~~	~~Fine Dust Silo T-388 Discharge to Truck (Vaculoader System)~~

~~**AD. System 28 - Kiln #3 Baghouse Fines Discharge System**~~

~~PF1.042~~	~~Fines Dust Silo T-388 Transfer to Pugmill (includes transfer of fully saturated material from pugmill to truck (PF1.042.1))~~

~~**AE. System 29 - Hydrate Plant Surge Bin**~~

~~S2.117~~	~~Conveyor C-1105 Transfer to Surge Bin N-1101~~
~~S2.117.1~~	~~Product Lime Silo T-44 Transfer to Gate G-1105~~
~~S2.117.2~~	~~Gate G-1105 Transfer to Conveyor C-1105~~
~~S2.118~~	~~Surge Bin N-1101 transfer to Conveyor C-1102~~
~~S2.118.1~~	~~Conveyor C-1102 Transfer to Conveyor C-1104~~
~~S2.119~~	~~Conveyor C-1104 Transfer to Hydrator Package~~

Issued to: GRAYMONT WESTERN US INC. – PILOT PEAK PLANT

Emission Unit List (continued):

~~AF. System 30 - Hydrate Plant Hydrator~~

~~S2.120~~	~~Hydrator~~
~~S2.121~~	~~Conveyor C-1122 Transfer to Gate G-1122~~

~~AG. System 31 - Hydrate Plant Lime Transfer (DC-1132)~~

~~S2.122~~	~~Gate G-1122 Transfer to Conveyor C-1123~~
~~S2.123~~	~~Separator Screen S-1130 and Associated Transfers (IN from Gate G-1122 and Bucket Elevator E-1130 (S2.130); OUT to Conveyor C-1130 (S2.124) and Conveyor C-1134 or Conveyor C-1132 (S2.128))~~
~~S2.125~~	~~Mill R-1130 and Associated Transfers (IN from Conveyor C-1130; OUT to Conveyor C-1131 (S2.129))~~
~~S2.126~~	~~Conveyor C-1131 Transfer to Bucket Elevator E-1130~~
~~S2.127~~	~~Separator Screen S-1131 and Associated Transfers (IN from Bucket Elevator E-1130; OUT to Conveyor C-1130, Conveyor C-1132, or Conveyor C-1134 (S2.128))~~
~~S2.131~~	~~Conveyor C-1134 and Conveyor C-1132 transfer to Bin N-1130~~

~~AH. System 32 - Hydrate Plant Lime Transfer to Silo T-1140 (DC-1140) (Revised August 2021, Air Case # 10886)~~

~~S2.132~~	~~Bin N-1130 Transfer to Gate G-1131~~
~~S2.132.1~~	~~Gate G-1131 to Gate G-1133~~
~~S2.135~~	~~Pneumatic Conveyor A-1130 Transfer to Loadout Silo T-1140 via Gate G-1133~~

~~AI. System 33 - Hydrate Plant Lime Transfer to Silo T-1141(Revised August 2021, Air Case # 10886)~~

~~S2.132~~	~~Bin N-1130 Transfer to Gate G-1131~~
~~S2.132.1~~	~~Gate G-1131 to Gate G-1133~~
~~S2.137~~	~~Pneumatic Conveyor A-1130 Transfer to Loadout Silo T-1141 via Gate G-1133~~

~~AJ. System 34 - Hydrate Silos Loadout~~

~~S2.136~~	~~Loadout Silo T-1140 Discharge via Conveyor C-1140~~
~~S2.138~~	~~Loadout Silo T-1141 Discharge via Conveyor C-1141~~

~~AK. System 35 - Product Lime Kiln #3 - Control Device #1 (D-331)~~

~~S2.144~~	~~Bucket Elevator E-331 Transfer to Gate G-331.1~~
~~S2.145~~	~~Gate G-331.1 Transfer to Gate G-331 or Silo T-40~~
~~S2.146~~	~~Gate G-331 Transfer to Core Bin N-332 or Conveyor C-333~~
~~S2.147~~	~~Conveyor C-333 Transfer to Kiln #3 Run Silo T-331~~
~~S2.148~~	~~Core Bin N-332 Discharge to Truck~~
~~S2.149~~	~~Bucket Elevator E-332 Transfer to Gate G-332.1~~
~~S2.149.1~~	~~Gate G-332.1 Transfer to Conveyor C-334 or Bin N-332~~
~~S2.150~~	~~Conveyor C-334 Transfer to #3 Kiln Run Silo T-331~~

Issued to: GRAYMONT WESTERN US INC. – PILOT PEAK PLANT

Emission Unit List (continued):

~~AL. System 36 - Product Lime Kiln #3 Control Device #2 (D-333)~~

~~S2.139~~	~~Kiln #3 Lime Cooler N-322 Transfer to Gate G-326~~
~~S2.140~~	~~Gate G-326 Transfer to Conveyor C-331~~
~~S2.141~~	~~Gate G-326 Transfer to Conveyor C-332~~
~~S2.142~~	~~Conveyor C-331 Transfer to Bucket Elevator E-331~~
~~S2.143~~	~~Conveyor C-332 Transfer to Bucket Elevator E-332~~
~~S2.151~~	~~Gate G-353 Transfer to Conveyor C-332~~
~~S2.152~~	~~Gate G-354 Transfer to Conveyor C-332~~
~~S2.154~~	~~Kiln #3 Run Silo T-331 Transfer via Feeder F-336 to Conveyor C-336~~
~~S2.155~~	~~Kiln #3 Run Silo T-331 Transfer via Feeder F-337 to Conveyor C-337~~
~~S2.156~~	~~Conveyor C-336 Transfer to Bucket Elevator E-336~~
~~S2.157~~	~~Conveyor C-337 Transfer to Bucket Elevator E-337~~
~~S2.158~~	~~Bucket Elevator E-336 Transfer to Gate G-336~~
~~S2.159~~	~~Screen S-336 and Associated Transfers (IN from Gate G-336; OUT to Crusher R-351 (S2.161), Gate G-351 (S2.162), and Gate G-353 (S2.165))~~
~~S2.160~~	~~Gate G-336 Transfer to Conveyor C-341~~
~~S2.163~~	~~Crusher R-351 and Associated Transfers (IN from Gate G-351 and Screen S-336 (S2.161); OUT to Screw Conveyor C-351 (S2.167))~~
~~S2.164~~	~~Gate G-351 transfer to Conveyor C-342~~
~~S2.166~~	~~Gate G-353 Transfer to Conveyor C-341~~
~~S2.168~~	~~Conveyor C-351 Transfer to Bucket Elevator E-336~~
~~S2.169~~	~~Bucket Elevator E-337 Transfer to Gate G-337~~
~~S2.170~~	~~Screen S-337 and Associated Transfers (IN from Gate G-337; OUT to Crusher R-352 (S2.172), Gate G-352 (S2.175), and Gate G-354 (S2.178)~~
~~S2.171~~	~~Gate G-337 Transfer to Conveyor C-341~~
~~S2.173~~	~~Crusher R-352 and Associated Transfer (IN from Screen S-337 (S2.172) and Gate G-352 (S2.176); OUT to Screw Conveyor C-352)~~
~~S2.174~~	~~Conveyor C-352 Transfer to Bucket Elevator E-337~~
~~S2.177~~	~~Gate G-352 Transfer to Conveyor C-342~~
~~S2.179~~	~~Gate G-354 Transfer to Conveyor C-341~~

~~AM. System 37 - Product Lime Kiln #3 - Control Device #3 (D-343)~~

~~S2.182~~	~~Conveyor C-341 Transfer to Bucket Elevator E-341~~
~~S2.183~~	~~Conveyor C-342 Transfer to Bucket Elevator E-342~~
~~S2.184~~	~~Bucket Elevator E-341 Transfer to Lime Silo T-343~~
~~S2.185~~	~~Bucket Elevator E-342 Transfer to Lime Silo T-342~~

~~AN. System 38 - Product Lime Kiln #3 - Control Device #4 (D-361)~~

~~S2.187~~	~~Lime Silo T-343 Loadout to Truck (via Spout U-362 or Transfer to Conveyor C-364)~~
~~S2.188~~	~~Lime Silo T-342 Loadout to Truck (via Spout U-363 or Transfer to Conveyor C-365)~~
~~S2.188.1~~	~~Conveyor C-364 and Conveyor C-365 Transfer to Truck via Spout U-364~~

~~AO. System 40 - Gasoline Storage Tank (5,700 gallons)~~

~~S2.189~~	~~Gasoline Storage Tank (5,700 gallon capacity)~~

~~AP. System 41 - Kiln #1 Auxiliary Drive Motor~~

~~S2.190~~	~~Kiln #1 Auxiliary Drive Motor (76.5 hp, Deutz, model F3L912, manufactured pre 1988)~~

Emission Unit List (continued):

~~AQ. System 42 - Kiln #2 Auxiliary Drive Motor~~
~~S2.191 Kiln #2 Auxiliary Drive Motor (123 hp, Perkins, Model LD33469, manufactured pre 1994)~~

~~AR. System 43 - Kiln #3 Auxiliary Drive Motor~~
~~S2.192 Kiln #3 Auxiliary Drive Motor (131 hp, Deutz, model F5L912, manufactured pre 1996)~~

~~AS. System 44 - Emergency Fire Pump~~
~~S2.193 Emergency Fire Pump (160 hp, Caterpillar, model CAT 3208, Pre 1989)~~

~~AT. System 45 - Toana Truck Unloading~~
~~PF1.043 Truck Unloading to Below-grade Hopper~~

~~AU. System 46 - Toana Railcar Loading~~
~~S2.194 Hopper Discharge to Conveyor~~
~~S2.195 Conveyor Discharge to Railcar via Loadout Spout~~

~~AV. System 47 - Fine Dust Surge Bin N-80 Transfer to Truck~~
~~PF1.044 Fine Dust Surge Bin N-80 transfer to Truck~~

~~AW. System 48 - Fine Dust Surge Bin N-280 Transfer to Truck~~
~~PF1.045 Fine Dust Surge Bin N-280 transfer to Truck~~

~~AX. System 49 - Fine Dust Surge Bin N-381 Transfer to Truck~~
~~PF1.046 Fine Dust Surge Bin N-381 transfer to Truck~~

~~AY. System 50 – Truck Dump to Hoppers #1 and #2 (Added September 2023, Air Case # 11483)~~
~~PF1.047 Truck Dump to Hoppers #1 and #2~~

~~AZ. System 51 – Hoppers #1 and #2 Discharge (Added September 2023, Air Case # 11483)~~
~~PF1.048 Hoppers #1 and #2 discharge to Belt Feeders #1 and #2~~
~~PF1.049 Belt Feeders #1 and #2 transfer to Reclaim Belt Conveyor~~

~~BA. System 52 – Pozzolan Silo (Added September 2023, Air Case # 11483)~~
~~S2.196 Pozzolan Silo Loading~~
~~PF1.050 Pozzolan Silo Discharge to Pozzolan Belt Feeder~~

~~BB. System 53 – Pozzolan Belt Feeder (Added September 2023, Air Case # 11483)~~
~~PF1.051 Pozzolan Belt Feeder transfer to Covered Z Belt~~

~~BC. System 54 – Quicklime Silo (Added September 2023, Air Case # 11483)~~
~~S2.197 Quicklime Silo Loading~~
~~PF1.052 Quicklime Silo Discharge to Quicklime Belt Feeder transfer~~

~~BD. System 55 – Quicklime Belt Feeder (Added September 2023, Air Case # 11483)~~
~~PF1.053 Quicklime Belt Feeder transfer to Covered Z Belt~~

~~BE. System 56 – GRAYBOND Ball Mill Air Classifier (Added September 2023, Air Case # 11483)~~
~~S2.198 Air Classifier and associated transfers (In: Ball Mill; Out: Ball Mill and Product Classifier Baghouse)~~

Emission Unit List (continued):

~~**BF. System 57 – GRAYBOND Ball Mill (Added September 2023, Air Case # 11483)**~~

~~S2.199~~	~~Ball Mill and associated transfers (In: Reclaim Belt Conveyor, Covered Z Belt, and Air Classifier; Out: Air Classifier via Enclosed Screw Conveyors, Main Storage Silos #1 and #2 via Enclosed Screw Conveyors)~~

~~**BG. System 58 – GRAYBOND Product Silos (Added September 2023, Air Case # 11483)**~~

~~S2.200~~	~~Main Storage Silo #060 Loading~~
~~S2.201~~	~~Main Storage Silo #070 Loading~~
~~S2.202~~	~~Main Storage Silo #060 Discharge to Truck~~
~~S2.203~~	~~Main Storage Silo #070 Discharge to Truck~~

******End of Emission Unit List******

Issued to: GRAYMONT WESTERN US INC. (AS PERMITTEE)

Section IV. Specific Operating Conditions (continued)

K. Emission Units S2.031 through S2.033

System 10 – Kiln #1 Circuit (D-85) (Revised June 2024, Air Case # 11821)		Location UTM (Zone 11, NAD 83)	
		m North	m East
S2.031	Kiln #1 Pre-heater PH-20	4,522,666	731,377
S2.032	Kiln #1 (K-20) and Associated Coal Mill R-92		
S2.033	Kiln #1 Lime Cooler N-21		

1. Air Pollution Control Equipment (NAC 445B.3405)
   a. Emissions from **S2.031 through S2.033** shall be controlled by a **baghouse (D-85)** and **Low-NO_X Burners**.
   ~~b. Descriptive Stack Parameters~~
   ~~Stack Height: 100.0 feet~~
   ~~Stack Diameter: 4.958 feet~~
   ~~Stack Temperature: 350 °F~~
   ~~Exhaust Flow: 60,000 dry standard cubic feet per minute (dscfm)~~

~~2. Operating Parameters (NAC 445B.3405)~~
   ~~a. The **S2.032** may combust, as the primary fuel source, **coal** only, with a maximum coal sulfur content of 3.0%. The use of diesel fuel or propane is designated for startups and flame stabilization purposes during the startup and/or shut down of the **S2.032**.~~
   ~~b. The maximum allowable fuel consumption rate for **S2.032** shall not exceed **5.0 tons of coal** per clock hour.~~
   ~~c. The maximum allowable production rate for **S2.031 through S2.033**, each, shall not exceed **25.0** tons of **lime** per hour, averaged over a calendar day.~~
   ~~d. Hours~~
      ~~(1) **S2.031 through S2.033**, each, may operate a total of **24** hours per day.~~

3. Emission Limits (NAC 445B.305, NAC 445B.3405, 40 CFR Part 51.308)
   a. The Permittee, upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from **the exhaust stack of baghouse (D-85)** the following pollutants in excess of the following specified limits:
      ~~(1) The discharge of **PM** (particulate matter) to the atmosphere shall not exceed **10.3** pounds per hour, nor more than **45.1** tons per 12-month rolling period.~~
      ~~(2) The discharge of **PM_{10}** (particulate matter less than or equal to 10 microns in diameter) to the atmosphere shall not exceed **13.6** pounds per hour, nor more than **59.6** tons per 12-month rolling period.~~
      ~~(3) The discharge of **$PM_{2.5}$** (particulate matter less than or equal to 2.5 microns in diameter) to the atmosphere shall not exceed **13.6** pounds per hour, nor more than **59.6** tons per 12-month rolling period.~~
      ~~(4) The discharge of **SO_2** (sulfur dioxide) to the atmosphere shall not exceed **14.0** pounds per hour, nor more than **61.3** tons per 12-month rolling period.~~
      ~~(5) The discharge of **NO_X** (oxides of nitrogen) to the atmosphere shall not exceed **180.0** pounds per hour, nor more than **526.0** tons per 12-month rolling period.~~
      ~~(6) The discharge of **CO** (carbon monoxide) to the atmosphere shall not exceed **308.0** pounds per hour, nor more than **1,349.0** tons per 12-month rolling period.~~
      ~~(7) The discharge of **VOCs** (volatile organic compounds) to the atmosphere shall not exceed **4.35** pounds per hour, nor more than **19.1** tons per 12-month rolling period.~~
      ~~(8) NAC 445B.22017 – The opacity from **baghouse (D-85)** shall not equal or exceed **20** percent.~~
      ~~(9) NAC 445B.2203 – The maximum allowable discharge of **PM_{10}** to the atmosphere from **baghouse (D-85)** shall not exceed **0.33** pound per MMBtu.~~
      ~~(10) NAC 445B.22047 – The maximum allowable discharge of **sulfur** to the atmosphere from **baghouse (D-85)** shall not exceed **91.0** pounds per MMBtu.~~
      ~~(11) NAC 445B.22033 – The maximum allowable discharge of **PM_{10}** to the atmosphere from **baghouse (D-85)** shall not exceed **35.4** pounds per hour.~~

Issued to: GRAYMONT WESTERN US INC. (AS PERMITTEE)

Section IV. Specific Operating Conditions (continued)

K. Emission Units S2.031 through S2.033 (continued)

3. Emission Limits (NAC 445B.305, NAC 445B.3405, 40 CFR Part 51.308) (continued)
   b. The Permittee, within 240 days upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from **the exhaust stack of baghouse (D-85)** the following pollutants in excess of the following specified limits:
      (1) Nevada Regional Haze SIP Limit – The discharge of **NO_X** to the atmosphere shall not exceed **101.4** pounds per hour, based on a 30-day rolling average period.

4. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405)
   The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.
   ~~a. Monitor and record the hours of operation for **S2.031 through S2.033**, each, for each calendar day.~~
   ~~b Monitor and record the consumption rate of **coal** on an hourly basis for **Kiln #1 Circuit** (in **tons**).~~
   ~~c. Monitor and record the production rate of **lime** for **Kiln #1 Circuit** for each calendar day.~~
   ~~d. Record the coal sulfur content as demonstrated and submitted by the coal supplier data for each calendar day.~~
   ~~e. Record the monthly consumption rate and the corresponding annual consumption rate for the 12-month rolling period. The monthly consumption rate shall be determined at the end of each month as the sum of hourly consumption rate for each day of the month. The annual consumption rate shall be determined at the end of each month as the sum of the monthly consumption rate for the 12-month rolling period.~~
   ~~f. Record the corresponding average hourly production rate of **lime** in tons per hour. The average hourly production rate shall be determined from the total daily production and the total daily hours of operation.~~
   ~~g. Annually, conduct and record an internal inspection of **Baghouse (D-85)**, including the bags. In the event that **Kiln #1 Circuit** operates without prolonged shutdown for an entire calendar year, and COMS data or **Kiln #1 Circuit** indicates that **Baghouse (D-85)** is operating properly, the internal baghouse inspection or dye test may be conducted during the next prolonged shutdown that will allow safe access inside **Baghouse (D-85)**.~~
   ~~h. Inspect the baghouse installed on **Kiln #1 Circuit** on a **monthly** basis in accordance with the manufacturer's operation and maintenance manual and record the results (e.g. the condition of the filter fabric), and any corrective actions taken.~~
   ~~i. Maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. (40 CFR 60.7(b))~~
   ~~j. Install, calibrate, operate, and maintain a SO_2 Continuous Emissions Monitoring System (CEMS) as specified in **Section V.A.** of this operating permit.~~
   ~~k. Install, calibrate, operate, and maintain a Continuous Opacity Monitoring System (COMS) as specified in **Section VI.A.** of this operating permit.~~
   ~~l. Monitor the bag cleaning air pressure for **Baghouse D-85** every two weeks.~~
   ~~m. Record any corrective actions taken to maintain the bag cleaning air pressure for **Baghouse D-85** at or above 20 psi.~~

Issued to: GRAYMONT WESTERN US INC. (AS PERMITTEE)

Section IV. Specific Operating Conditions (continued)

K. Emission Units S2.031 through S2.033 (continued)

4. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405) (continued)
The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.

~~n. For the **Kiln #1 Circuit** startup:~~
~~(1) The time startup began.~~
~~(2) The time coal firing began.~~
~~(3) The time off-gases were routed through **Baghouse D-85**.~~
~~(4) **Baghouse D-85** inlet temperature when the kiln off-gases were routed through **Baghouse D-85**.~~
~~(5) Records documenting why any deviation from the best management practices plan for the **Kiln #1 Circuit** startup was necessary.~~
~~(6) Stack opacity as measured by the COMS.~~

~~o. The measured opacity (in percent opacity) from the COMS required in **Section VI.A.** of this operating permit. The opacity will be determined from reducing all data from the successive 10-second readings and recorded for each 6-minute average as required in NAC 445B.22017(1)(b), and as set forth in 40 CFR Part 60.13(h).~~

~~p. The emission rates of SO_2 in pounds per hour (lbs/hr) and parts per million (ppm) measured by the CEMS required in **Section V.A.** of this operating permit, for each averaging period described below:~~
~~(1) The SO_2 emissions in pounds per hour (lbs/hr) for each 3-hour rolling period.~~
~~(2) The following equation articulates the defining formula by which the pertinent data is calculated:~~

$$\cancel{E_h = K * C_{hp} * Q_{hs} * \left(\frac{100 - \%H_2O}{100}\right)}$$

~~where:~~

~~E_h = Hourly SO_2 mass emission rate during unit operation, lb/hr.~~

~~$K = 1.660 \times 10^{-7}$ for SO_2, (lb/scf)/ppm.~~

~~C_{hp} = Hourly average SO_2 concentration during unit operation, ppm (dry).~~

~~Q_{hs} = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).~~

~~$\%H_2O$ = Hourly average stack moisture content during unit operation or constant moisture value, percent by volume.~~

Issued to: GRAYMONT WESTERN US INC. (AS PERMITTEE)

Section IV. <u>Specific Operating Conditions</u> (continued)

K. Emission Units S2.031 through S2.033 (continued)

4. <u>Monitoring, Recordkeeping, and Reporting</u> (NAC 445B.3405) (continued)
The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.
   q. The emission rates of NO_X in pounds per hour (lbs/hr) and parts per million (ppm) measured by the CEMS required in **Section V.B.** of this operating permit, for each averaging period described below:
      (1) The NO_X emissions in pounds per hour (lbs/hr) for each 30-day rolling period.
      (2) The NO_X emissions in pounds per hour (lbs/hr) for each 3-hour rolling period.
      (3) The following equation articulates the defining formula by which the pertinent data is calculated:

$$E_h = K * C_{hp} * Q_{hs} * \left(\frac{100 - \%H_2O}{100} \right)$$

where:

E_h = Hourly NO_X mass emission rate during unit operation, lb/hr.

K = 1.194×10^{-7} for NO_X, (lb/scf)/ppm.

C_{hp} = Hourly average NO_X concentration during unit operation, ppm (dry).

Q_{hs} = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).

$\%H_2O$ = Hourly average stack moisture content during unit operation or constant moisture value, percent by volume.

   ~~r. As a result of the most recent performance tests performed in **K.5.a. through j**. of this section, the permittee shall derive emission factors for each of the following:~~
      ~~(1) Pounds of PM per ton of lime production (lbs-PM/ton-lime production)~~
      ~~(2) Pounds of PM_{10} per ton of lime production (lbs-PM_{10}/ton-lime production)~~
      ~~(3) Pounds of $PM_{2.5}$ per ton of lime production (lbs-$PM_{2.5}$/ton-lime production)~~
      ~~(4) Pounds of NO_x per ton of lime production (lbs-NO_x/ton-lime production)~~
      ~~(5) Pounds of CO per ton of lime production (lbs-CO/ton-lime production)~~
      ~~(6) Pounds of VOC's per ton of lime production (lbs-VOC's/ton-lime production)~~
   ~~s. The annual emissions of PM, PM_{10}, $PM_{2.5}$, CO, and VOC's from the **Kiln #1 Circuit** will be calculated based on the testing contained in **K.5.** of this section and then converted to tons of emissions per year.~~
   ~~t. The annual emissions of SO_2 from the **Kiln #1 Circuit** will be calculated based on the data recorded by the CEMs in **Section V.A.** of this operating permit and then converted to tons of emissions per year.~~
   u. The annual emissions of NO_X from the **Kiln #1 Circuit** will be calculated based on the data recorded by the CEMs in **Section V.B.** of this operating permit and then converted to tons of emissions per year.

Issued to: GRAYMONT WESTERN US INC. (AS PERMITTEE)

Section IV. Specific Operating Conditions (continued)

N. Emission Units S2.036 through S2.038

System 13 - Kiln #2 Circuit (D-285 (Revised June 2024, Air Case # 11821)		Location UTM (Zone 11, NAD 83)	
		m North	m East
S2.036	Kiln #2 Pre-heater PH-220	4,522,713	731,369
S2.037	Kiln #2 (K-220) and Associated Coal Mill R-292		
S2.038	Kiln #2 Lime Cooler N-221		

1. Air Pollution Control Equipment (NAC 445B.3405)
   a. Emissions from **S2.036 through S2.038** shall be controlled by a **baghouse (D-285)** and **Low-NO_X Burners**.
   ~~b. Descriptive Stack Parameters~~
   ~~Stack Height: 100.0 feet~~
   ~~Stack Diameter: 7.04 feet~~
   ~~Stack Temperature: 350 °F~~
   ~~Exhaust Flow: 70,000 dry standard cubic feet per minute (dscfm)~~

~~2. Operating Parameters (NAC 445B.3405)~~
   ~~a. The **S2.037** may combust, as the primary fuel source, **coal** only, with a maximum coal sulfur content of 3.0%. The use of diesel fuel or propane is designated for startups and flame stabilization purposes during the startup and/or shut down of the **S2.037**.~~
   ~~b. The maximum allowable fuel consumption rate for **S2.037** shall not exceed **7.5 tons of coal** per clock hour.~~
   ~~c. The maximum allowable throughput rate for **S2.036 through S2.038**, each, shall not exceed **33.3** tons of **lime** per hour, averaged over a calendar day.~~
   ~~d. Hours~~
   ~~(1) **S2.036 through S2.038**, each, may operate a total of **24** hours per day.~~

3. Emission Limits (NAC 445B.305, NAC 445B.3405, 40 CFR Part 51.308)
   a. The Permittee, upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from **the exhaust stack of baghouse (D-285)** the following pollutants in excess of the following specified limits:
   ~~(1) The discharge of **PM** (particulate matter) to the atmosphere shall not exceed **12.0** pounds per hour, nor more than **52.6** tons per 12-month rolling period.~~
   ~~(2) The discharge of **PM_{10}** (particulate matter less than or equal to 10 microns in diameter) to the atmosphere shall not exceed **15.2** pounds per hour, nor more than **66.6** tons per 12-month rolling period.~~
   ~~(3) The discharge of **$PM_{2.5}$** (particulate matter less than or equal to 2.5 microns in diameter) to the atmosphere shall not exceed **15.2** pounds per hour, nor more than **66.6** tons per 12-month rolling period.~~
   ~~(4) The discharge of **SO_2** (sulfur dioxide) to the atmosphere shall not exceed **21.0** pounds per hour, nor more than **92.0** tons per 12-month rolling period.~~
   ~~(5) The discharge of **NO_X** (oxides of nitrogen) to the atmosphere shall not exceed **240.0** pounds per hour, nor more than **701.0** tons per 12-month rolling period.~~
   ~~(6) The discharge of **CO** (carbon monoxide) to the atmosphere shall not exceed **410.0** pounds per hour, nor more than **1,796.0** tons per 12-month rolling period.~~
   ~~(7) The discharge of **VOCs** (volatile organic compounds) to the atmosphere shall not exceed **6.53** pounds per hour, nor more than **28.6** tons per 12-month rolling period.~~
   ~~(8) NAC 445B.22017 – The opacity from the **baghouse (D-285)** shall not equal or exceed **20** percent.~~
   ~~(9) NAC 445B.2203 – The maximum allowable discharge of **PM_{10}** to the atmosphere from **baghouse (D-285)** shall not exceed **0.30** pound per MMBtu.~~
   ~~(10) NAC 445B.22047 – The maximum allowable discharge of **sulfur** to the atmosphere from **baghouse (D-285)** shall not exceed **136.5** pounds per MMBtu.~~
   ~~(11) NAC 445B.22033 – The maximum allowable discharge of **PM_{10}** to the atmosphere from **baghouse (D-285)** shall not exceed **40.9** pounds per hour.~~

Issued to: GRAYMONT WESTERN US INC. (AS PERMITTEE)

Section IV. Specific Operating Conditions (continued)

N. Emission Units S2.036 through S2.038 (continued)

3. Emission Limits (NAC 445B.305, NAC 445B.3405, 40 CFR Part 51.308) (continued)
   b. The Permittee, within 240 days upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from **the exhaust stack of baghouse (D-285)** the following pollutants in excess of the following specified limits:
      (1) Nevada Regional Haze SIP Limit – The discharge of **NO_X** to the atmosphere shall not exceed **107.4** pounds per hour, based on a 30-day rolling average period.

4. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405)
   The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.
   ~~a. Monitor and record the hours of operation for **S2.036 through S2.038**, each, for each calendar day.~~
   ~~b Monitor and record the consumption rate of **coal** on an hourly basis for **Kiln #2 Circuit** (in **tons**).~~
   ~~c. Monitor and record the production rate of **lime** for **Kiln #2 Circuit** for each calendar day.~~
   ~~d. Record the coal sulfur content as demonstrated and submitted by the coal supplier data for each calendar day.~~
   ~~e. Record the monthly consumption rate and the corresponding annual consumption rate for the 12-month rolling period. The monthly consumption rate shall be determined at the end of each month as the sum of hourly consumption rate for each day of the month. The annual consumption rate shall be determined at the end of each month as the sum of the monthly consumption rate for the 12-month rolling period.~~
   ~~f. Record the corresponding average hourly production rate of **lime** in tons per hour. The average hourly production rate shall be determined from the total daily production and the total daily hours of operation.~~
   ~~g. Annually, conduct and record an internal inspection of **Baghouse (D-285)**, including the bags. In the event that **Kiln #2 Circuit** operates without prolonged shutdown for an entire calendar year, and COMS data or **Kiln #2 Circuit** indicates that **Baghouse (D-285)** is operating properly, the internal baghouse inspection or dye test may be conducted during the next prolonged shutdown that will allow safe access inside **Baghouse (D-285)**.~~
   ~~h. Inspect the baghouse installed on **Kiln #2 Circuit** on a **monthly** basis in accordance with the manufacturer's operation and maintenance manual and record the results (e.g. the condition of the filter fabric), and any corrective actions taken.~~
   ~~i. Maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. (40 CFR 60.7(b))~~
   ~~j. Install, calibrate, operate, and maintain a SO_2 Continuous Emissions Monitoring System (CEMS) as specified in **Section V.A.** of this operating permit.~~
   ~~k. Install, calibrate, operate, and maintain a Continuous Opacity Monitoring System (COMS) as specified in **Section VI.A.** of this operating permit.~~
   ~~l. Monitor the bag cleaning air pressure for **Baghouse D-285** every two weeks.~~
   ~~m. Record any corrective actions taken to maintain the bag cleaning air pressure for **Baghouse D-285** at or above 20 psi.~~

Section IV. Specific Operating Conditions (continued)

N. Emission Units S2.036 through S2.038 (continued)

4. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405) (continued)
The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.

~~n. For the **Kiln #2 Circuit** startup:~~
- ~~(1) The time startup began.~~
- ~~(2) The time coal firing began.~~
- ~~(3) The time off-gases were routed through **Baghouse D-285**.~~
- ~~(4) **Baghouse D-285** inlet temperature when the kiln off-gases were routed through **Baghouse D-285**.~~
- ~~(5) Records documenting why any deviation from the best management practices plan for the **Kiln #2 Circuit** startup was necessary.~~
- ~~(6) Stack opacity as measured by the COMS.~~

~~o. The measured opacity (in percent opacity) from the COMS required in **Section VI.A.** of this operating permit. The opacity will be determined from reducing all data from the successive 10-second readings and recorded for each 6-minute average as required in NAC 445B.22017(1)(b), and as set forth in 40 CFR Part 60.13(h).~~

~~p. The emission rates of SO_2 in pounds per hour (lbs/hr) and parts per million (ppm) measured by the CEMS required in **Section V.A.** of this operating permit, for each averaging period described below:~~
- ~~(1) The SO_2 emissions in pounds per hour (lbs/hr) for each 3-hour rolling period.~~
- ~~(2) The following equation articulates the defining formula by which the pertinent data is calculated:~~

$$\cancel{E_h = K * C_{hp} * Q_{hs} * \left(\frac{100 - \%H_2O}{100}\right)}$$

~~where:~~

~~E_h = Hourly SO_2 mass emission rate during unit operation, lb/hr.~~

~~$K = 1.660\times10^{-7}$ for SO_2, (lb/scf)/ppm.~~

~~C_{hp} = Hourly average SO_2 concentration during unit operation, ppm (dry).~~

~~Q_{hs} = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).~~

~~$\%H_2O$ = Hourly average stack moisture content during unit operation or constant moisture value, percent by volume.~~

Section IV. Specific Operating Conditions (continued)

N. Emission Units S2.036 through S2.038 (continued)

4. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405) (continued)
The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.

q. The emission rates of NO_X in pounds per hour (lbs/hr) and parts per million (ppm) measured by the CEMS required in **Section V.B.** of this operating permit, for each averaging period described below:
   (1) The NO_X emissions in pounds per hour (lbs/hr) for each 30-day rolling period.
   (2) The NO_X emissions in pounds per hour (lbs/hr) for each 3-hour rolling period.
   (3) The following equation articulates the defining formula by which the pertinent data is calculated:

$$E_h = K * C_{hp} * Q_{hs} * \left(\frac{100 - \%H_2O}{100} \right)$$

where:

E_h = Hourly NO_X mass emission rate during unit operation, lb/hr.

K = 1.194×10^{-7} for NO_X, (lb/scf)/ppm.

C_{hp} = Hourly average NO_X concentration during unit operation, ppm (dry).

Q_{hs} = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).

$\%H_2O$ = Hourly average stack moisture content during unit operation or constant moisture value, percent by volume.

~~r. As a result of the most recent performance tests performed in **N.5.a. through j**. of this section, the permittee shall derive emission factors for each of the following:~~
   ~~(1) Pounds of PM per ton of lime production (lbs-PM/ton-lime production)~~
   ~~(2) Pounds of PM_{10} per ton of lime production (lbs-PM_{10}/ton-lime production)~~
   ~~(3) Pounds of $PM_{2.5}$ per ton of lime production (lbs-$PM_{2.5}$/ton-lime production)~~
   ~~(4) Pounds of NO_x per ton of lime production (lbs-NO_x/ton-lime production)~~
   ~~(5) Pounds of CO per ton of lime production (lbs-CO/ton-lime production)~~
   ~~(6) Pounds of VOC's per ton of lime production (lbs-VOC's/ton-lime production)~~

~~s. The annual emissions of PM, PM_{10}, $PM_{2.5}$, CO, and VOC's from the **Kiln #2 Circuit** will be calculated based on the testing contained in **N.5.** of this section and then converted to tons of emissions per year.~~

~~t. The annual emissions of SO_2 from the **Kiln #2 Circuit** will be calculated based on the data recorded in **Section V.A.** of this operating permit and then converted to tons of emissions per year.~~

u. The annual emissions of NO_X from the **Kiln #2 Circuit** will be calculated based on the data recorded in **Section V.B.** of this operating permit and then converted to tons of emissions per year.

Issued to: GRAYMONT WESTERN US INC. (AS PERMITTEE)

Section IV. Specific Operating Conditions (continued)

S. Emission Units S2.042 through S2.044

System 17 - Kiln #3 Circuit (D-385) (Revised June 2024, Air Case # 11821)		Location UTM (Zone 11, NAD 83)	
		m North	m East
S2.042	Kiln #3 Pre-heater PH-321	4,522,532	731,431
S2.043	Kiln #3 (K-321) and Associated Coal Mill R-392		
S2.044	Kiln #3 Lime Cooler N-332		

1. Air Pollution Control Equipment (NAC 445B.3405)
   a. Emissions from **S2.042 through S2.044** shall be controlled by a **baghouse (D-385)** and **Low-NO_X Burners**.
   ~~b.~~ ~~Descriptive Stack Parameters~~
   ~~Stack Height: 181.0 feet~~
   ~~Stack Diameter: 7.04 feet~~
   ~~Stack Temperature: 350 °F~~
   ~~Exhaust Flow: 100,000 dry standard cubic feet per minute (dscfm)~~

~~2.~~ ~~Operating Parameters (NAC 445B.3405)~~
   ~~a.~~ ~~The **S2.043** may combust, as the primary fuel source, **coal** only, with a maximum coal sulfur content of 3.0%. The use of diesel fuel or propane is designated for startups and flame stabilization purposes during the startup and/or shut down of the **S2.043**.~~
   ~~b.~~ ~~The maximum allowable fuel consumption rate for **S2.043** shall not exceed **12.0 tons of coal** per clock hour.~~
   ~~c.~~ ~~The maximum allowable throughput rate for **S2.042 through S2.044**, each, shall not exceed **50.0** tons of **lime** per hour, averaged over a calendar day.~~
   ~~d.~~ ~~Hours~~
      ~~(1)~~ ~~**S2.042 through S2.044**, each, may operate a total of **24** hours per day.~~

3. Emission Limits (NAC 445B.305, NAC 445B.3405, 40 CFR Part 51.308)
   a. The Permittee, upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from **the exhaust stack of baghouse (D-385)** the following pollutants in excess of the following specified limits:
      ~~(1)~~ ~~The discharge of **PM** (particulate matter) to the atmosphere shall not exceed **17.1** pounds per hour, nor more than **75.1** tons per 12-month rolling period.~~
      ~~(2)~~ ~~The discharge of **PM_{10}** (particulate matter less than or equal to 10 microns in diameter) to the atmosphere shall not exceed **23.7** pounds per hour, nor more than **103.8** tons per 12-month rolling period.~~
      ~~(3)~~ ~~The discharge of **$PM_{2.5}$** (particulate matter less than or equal to 2.5 microns in diameter) to the atmosphere shall not exceed **23.7** pounds per hour, nor more than **103.8** tons per 12-month rolling period.~~
      ~~(4)~~ ~~The discharge of **SO_2** (sulfur dioxide) to the atmosphere shall not exceed **33.0** pounds per hour, nor more than **144.5** tons per 12-month rolling period.~~
      ~~(5)~~ ~~The discharge of **NO_X** (oxides of nitrogen) to the atmosphere shall not exceed **300.0** pounds per hour, nor more than **876.0** tons per 12-month rolling period.~~
      ~~(6)~~ ~~The discharge of **CO** (carbon monoxide) to the atmosphere shall not exceed **512.5** pounds per hour, nor more than **2,245.0** tons per 12-month rolling period.~~
      ~~(7)~~ ~~The discharge of **VOCs** (volatile organic compounds) to the atmosphere shall not exceed **10.4** pounds per hour, nor more than **45.7** tons per 12-month rolling period.~~
      ~~(8)~~ ~~NAC 445B.22017 – The opacity from the **baghouse (D-385)** shall not equal or exceed **20** percent.~~
      ~~(9)~~ ~~NAC 445B.2203 – The maximum allowable discharge of **PM_{10}** to the atmosphere from **baghouse (D-385)** shall not exceed **0.27** pound per MMBtu.~~
      ~~(10)~~ ~~NAC 445B.22047 – The maximum allowable discharge of **sulfur** to the atmosphere from **baghouse (D-385)** shall not exceed **187.2** pounds per MMBtu.~~
      ~~(11)~~ ~~NAC 445B.22033 – The maximum allowable discharge of **PM_{10}** to the atmosphere from **baghouse (D-385)** shall not exceed **44.6** pounds per hour.~~

Issued to: GRAYMONT WESTERN US INC. (AS PERMITTEE)

Section IV. Specific Operating Conditions (continued)

S. Emission Units S2.042 through S2.044 (continued)

3. Emission Limits (NAC 445B.305, NAC 445B.3405, 40 CFR Part 51.308) (continued)
   b. The Permittee, within 240 days upon issuance of this operating permit, shall not discharge or cause the discharge into the atmosphere from **the exhaust stack of baghouse (D-385)** the following pollutants in excess of the following specified limits:
      (1) Nevada Regional Haze SIP Limit – The discharge of **NO_X** to the atmosphere shall not exceed **143.7** pounds per hour, based on a 30-day rolling average period.

4. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405)
   The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.
   ~~a. Monitor and record the hours of operation for **S2.042 through S2.044**, each, for each calendar day.~~
   ~~b Monitor and record the consumption rate of **coal** on an hourly basis for **Kiln #3 Circuit** (in **tons**).~~
   ~~c. Monitor and record the production rate of **lime** for **Kiln #3 Circuit** for each calendar day.~~
   ~~d. Record the coal sulfur content as demonstrated and submitted by the coal supplier data for each calendar day.~~
   ~~e. Record the monthly consumption rate and the corresponding annual consumption rate for the 12-month rolling period. The monthly consumption rate shall be determined at the end of each month as the sum of hourly consumption rate for each day of the month. The annual consumption rate shall be determined at the end of each month as the sum of the monthly consumption rate for the 12-month rolling period.~~
   ~~f. Record the corresponding average hourly production rate of **lime** in tons per hour. The average hourly production rate shall be determined from the total daily production and the total daily hours of operation.~~
   ~~g. Annually, conduct and record an internal inspection of **Baghouse (D-385)**, including the bags. In the event that **Kiln #3 Circuit** operates without prolonged shutdown for an entire calendar year, and COMS data or **Kiln #3 Circuit** indicates that **Baghouse (D-385)** is operating properly, the internal baghouse inspection or dye test may be conducted during the next prolonged shutdown that will allow safe access inside **Baghouse (D-385)**.~~
   ~~h. Inspect the baghouse installed on **Kiln #3 Circuit** on a **monthly** basis in accordance with the manufacturer's operation and maintenance manual and record the results (e.g. the condition of the filter fabric), and any corrective actions taken.~~
   ~~i. Maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. (40 CFR 60.7(b))~~
   ~~j. Install, calibrate, operate, and maintain a SO_2 Continuous Emissions Monitoring System (CEMS) as specified in **Section V.A.** of this operating permit.~~
   ~~k. Install, calibrate, operate, and maintain a Continuous Opacity Monitoring System (COMS) as specified in **Section VI.A.** of this operating permit.~~
   ~~l. Monitor the bag cleaning air pressure for **Baghouse D-385** every two weeks.~~
   ~~m. Record any corrective actions taken to maintain the bag cleaning air pressure for **Baghouse D-385** at or above 20 psi.~~

Section IV. Specific Operating Conditions (continued)

S. Emission Units S2.042 through S2.044 (continued)

4. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405) (continued)
The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.

~~n. For the **Kiln #3 Circuit** startup:~~
~~(1) The time startup began.~~
~~(2) The time coal firing began.~~
~~(3) The time off-gases were routed through **Baghouse D-385**.~~
~~(4) **Baghouse D-385** inlet temperature when the kiln off-gases were routed through **Baghouse D-385**.~~
~~(5) Records documenting why any deviation from the best management practices plan for the **Kiln #3 Circuit** startup was necessary.~~
~~(6) Stack opacity as measured by the COMS.~~

~~o. The measured opacity (in percent opacity) from the COMS required in **Section VI.A.** of this operating permit. The opacity will be determined from reducing all data from the successive 10-second readings and recorded for each 6-minute average as required in NAC 445B.22017(1)(b), and as set forth in 40 CFR Part 60.13(h).~~

~~p. The emission rates of SO_2 in pounds per hour (lbs/hr) and parts per million (ppm) measured by the CEMS required in **Section V.A.** of this operating permit, for each averaging period described below:~~
~~(1) The SO_2 emissions in pounds per hour (lbs/hr) for each 3-hour rolling period.~~
~~(2) The following equation articulates the defining formula by which the pertinent data is calculated:~~

$$\cancel{E_h = K * C_{hp} * Q_{hs} * \left(\frac{100 - \%H_2O}{100} \right)}$$

~~where:~~

~~E_h = Hourly SO_2 mass emission rate during unit operation, lb/hr.~~

~~$K = 1.660\times10^{-7}$ for SO_2, (lb/scf)/ppm.~~

~~C_{hp} = Hourly average SO_2 concentration during unit operation, ppm (dry).~~

~~Q_{hs} = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).~~

~~$\%H_2O$ = Hourly average stack moisture content during unit operation or constant moisture value, percent by volume.~~

Section IV. Specific Operating Conditions (continued)

S. Emission Units S2.042 through S2.044 (continued)

4. Monitoring, Recordkeeping, and Reporting (NAC 445B.3405) (continued)
The Permittee, upon the issuance of this operating permit, shall maintain, in a contemporaneous log, the monitoring and recordkeeping specified in this section. All records in the log must be identified with the calendar date of the record. All specified records shall be entered into the log at the end of the shift, end of the day of operation, or the end of the final day of operation for the month, as appropriate.

q. The emission rates of NO_X in pounds per hour (lbs/hr) and parts per million (ppm) measured by the CEMS required in **Section V.B.** of this operating permit, for each averaging period described below:
(1) The NO_X emissions in pounds per hour (lbs/hr) for each 30-day rolling period.
(2) The NO_X emissions in pounds per hour (lbs/hr) for each 3-hour rolling period.
(3) The following equation articulates the defining formula by which the pertinent data is calculated:

$$E_h = K * C_{hp} * Q_{hs} * \left(\frac{100 - \%H_2O}{100}\right)$$

where:

E_h = Hourly NO_X mass emission rate during unit operation, lb/hr.

K = 1.194×10^{-7} for NO_X, (lb/scf)/ppm.

C_{hp} = Hourly average NO_X concentration during unit operation, ppm (dry).

Q_{hs} = Hourly average volumetric flow rate during unit operation, scfh as measured (wet).

$\%H_2O$ = Hourly average stack moisture content during unit operation or constant moisture value, percent by volume.

~~r. As a result of the most recent performance tests performed in **S.5.a. through j**. of this section, the permittee shall derive emission factors for each of the following:~~
~~(1) Pounds of PM per ton of lime production (lbs-PM/ton-lime production)~~
~~(2) Pounds of PM_{10} per ton of lime production (lbs-PM_{10}/ton-lime production)~~
~~(3) Pounds of $PM_{2.5}$ per ton of lime production (lbs-$PM_{2.5}$/ton-lime production)~~
~~(4) Pounds of NO_x per ton of lime production (lbs-NO_x/ton-lime production)~~
~~(5) Pounds of CO per ton of lime production (lbs-CO/ton-lime production)~~
~~(6) Pounds of VOC's per ton of lime production (lbs-VOC's/ton-lime production)~~

~~s. The annual emissions of PM, PM_{10}, $PM_{2.5}$, CO, and VOC's from the **Kiln #3 Circuit** will be calculated based on the testing contained in **S.5.** of this section and then converted to tons of emissions per year.~~

~~t. The annual emissions of SO_2 from the **Kiln #3 Circuit** will be calculated based on the data recorded in **Section V.A.** of this operating permit and then converted to tons of emissions per year.~~

u. The annual emissions of NO_X from the **Kiln #3 Circuit** will be calculated based on the data recorded in **Section V.B.** of this operating permit and then converted to tons of emissions per year.

Section V. Continuous Emissions Monitoring System (CEMS) Conditions (continued)

~~**A. SO_2 CEMS Requirements for System 10 (S2.031, S2.032, and S2.033), System 13 (S2.036, S2.037, and S2.038), and System 17 (S2.042, S2.043, and S2.044)** (NAC 445B.3405) (continued)~~

~~8. Unless specified otherwise in the applicable subpart, the Permittee shall comply with the relative accuracy criteria:~~
   ~~a. For RATA (40 CFR Part 60 Appendix F Procedure 1 Section 5.2.3(1)):~~
      ~~(1) For **SO_2** emissions, RA shall be less than or equal to 20% (if the value determined by the Reference Method (RM) is greater than 50% of the emission limit) or RA shall be less than or equal to 10% (if the value determined by the RM is less than 50% of the emission limit). (40 CFR Part 60 Appendix B PS-2 Section 13.2)~~
   ~~b. For CGA ±15 percent of the average audit value for ±5 ppm, whichever is greater. (40 CFR Part 60 Appendix F Procedure 1 Section 5.2.3(2))~~

~~9. The Permittee shall conduct and report to the Director a quarterly audit as specified under 40 CFR Part 60 Appendix F Procedure 1 Section 7.0. (40 CFR Part 60 Appendix F Procedure 1 Section 7.0)~~

B. NO_X (CEMS) Requirements for System 10 (S2.031, S2.032, and S2.033), System 13 (S2.036, S2.037, and S2.038), and System 17 (S2.042, S2.043, and S2.044) (NAC 445B.3405)

1. Within 240 days upon issuance of this operating permit, the Permittee shall install, calibrate, operate, and maintain a **NO_X** CEMS in the exhaust stacks of **System 10 (S2.031, S2.032, and S2.033)**, **System 13 (S2.036, S2.037, and S2.038)**, and **System 17 (S2.042, S2.043, and S2.044)**, each. The CEMS sampling probe must be installed at an appropriate location in the exhaust stacks to accurately and continuously measure the concentration of **NO_X** (in ppm) from **System 10 (S2.031, S2.032, and S2.033)**, **System 13 (S2.036, S2.037, and S2.038)**, and **System 17 (S2.042, S2.043, and S2.044)**, in accordance with the requirements prescribed in Nevada Administrative Code (NAC) 445B.252 to NAC 445B.267, applicable subparts 40 CFR Part 60 Appendix B and Appendix F. Verification of the operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the devices.

2. The Permittee shall comply with the following method performance specifications (40 CFR Part 60 Appendix B PS-2 Section 13.0):
   a. Calibration Drift
   b. Relative Accuracy

3. The Permittee shall develop and implement a Quality Control (QC) program. As a minimum, each QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities (40 CFR Part 60 Appendix F Procedure 1 Section 3.0):
   a. Calibration of CEMS
   b. Calibration maintenance of CEMS (including spare parts inventory)
   c. Preventative maintenance of CEMS (including spare parts inventory)
   d. Data recording, calculations, and reporting
   e. Accuracy audit procedures including sampling and analysis methods
   f. Program of corrective action for malfunctioning CEMS

4. The written procedures under **V.A.3.** of this section, must be kept on record and available for inspection by the Director. (40 CFR Part 60 Appendix F Procedure 1 Section 3.0)

5. The Permittee shall conduct a Calibration Drift Assessment according to 40 CFR Part 60 Appendix F Procedure 1 Sections 4.1 and 4.2. (40 CFR Part 60 Appendix F Procedure 1 Sections 4.1 and 4.2).

6. The Permittee shall record and report all CEMS data according to 40 CFR Part 60 Appendix F Procedure 1 Section 4.4. All measurements from the CEMS must be retained on file by the Permittee for at least 2 years. (40 CFR Part 60 Appendix F Procedure 1 Section 4.4)

Section V. Continuous Emissions Monitoring System (CEMS) Conditions (continued)

B. NO_X (CEMS) Requirements for System 10 (S2.031, S2.032, and S2.033), System 13 (S2.036, S2.037, and S2.038), and System 17 (S2.042, S2.043, and S2.044) (NAC 445B.3405) (continued)

7. Each CEMS must be audited at least once each calendar quarter. Successive quarterly audits shall occur no closer than 2 months. The audits shall be conducted as follows (40 CFR Part 60 Appendix F Procedure 1 Section 5.1):
   a. The Relative Accuracy Test (RATA) shall be conducted once every four calendar quarters. (40 CFR Part 60 Appendix F Procedure 1 Section 5.1.1)
   b. The Cylinder Gas Audit (CGA) shall be conducted every quarter except when a RATA is conducted. (40 CFR Part 60 Appendix F Procedure 1 Section 5.1.2)

8. Unless specified otherwise in the applicable subpart, the Permittee shall comply with the relative accuracy criteria:
   a. For RATA (40 CFR Part 60 Appendix F Procedure 1 Section 5.2.3(1)):
      (1) For **NO_X** emissions, RA shall be less than or equal to 20% (if the value determined by the Reference Method (RM) is greater than 50% of the emission limit) or RA shall be less than or equal to 10% (if the value determined by the RM is less than 50% of the emission limit). (40 CFR Part 60 Appendix B PS-2 Section 13.2)
   b. For CGA ±15 percent of the average audit value for ±5 ppm, whichever is greater. (40 CFR Part 60 Appendix F Procedure 1 Section 5.2.3(2))

9. The Permittee shall conduct and report to the Director a quarterly audit as specified under 40 CFR Part 60 Appendix F Procedure 1 Section 7.0. (40 CFR Part 60 Appendix F Procedure 1 Section 7.0)

C. NAC 445B.265

Monitoring systems: Records; Reports

1. The Permittee subject to the provisions of NAC 445B.256 to 445B.267, inclusive, shall maintain records of the occurrence and duration of any start-up, shutdown or malfunction in the operation of an affected facility and any malfunction of the air pollution control equipment or any periods during which a continuous monitoring system or monitoring device is inoperative.
2. The Permittee required to install a continuous monitoring system shall submit a written report of excess emissions to the director for every calendar quarter. All quarterly reports must be postmarked by the 30th day following the end of each calendar quarter and must include the following information:
   a. The magnitude of excess emissions computed in accordance with NAC 445B.256 to 445B.267, inclusive, any conversion factors used, and the date and time of commencement and completion of each time period of excess emissions.
   b. Specific identification of each period of excess emissions that occurs during start-ups, shutdowns and malfunctions of the affected facility.
   c. The nature and cause of any malfunction, if known, the corrective action taken or preventative measures adopted.
   d. Specific identification of each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of any repairs or adjustments that were made.
      (1) When no excess emissions have occurred and the continuous monitoring system has not been inoperative, repaired or adjusted, such information shall be included in the report.

Section V. Continuous Emissions Monitoring System (CEMS) Conditions (continued)

C. NAC 445B.265 (continued)

Monitoring systems: Records; Reports (continued)

3. The Permittee subject to the provisions of NAC 445B.256 to 445B.267, inclusive, shall maintain a file of all measurements, including:
   a. Continuous monitoring systems, monitoring devices and performance testing measurements;
   b. All continuous monitoring system performance evaluations;
   c. All continuous monitoring systems or monitoring device calibration checks;
   d. Adjustments and maintenance performed on these systems or devices; and
   e. All other information required by NAC 445B.256 to 445B.267, inclusive, recorded in a permanent form suitable for inspection.
      (1) The file shall be retained for at least 2 years following the date of the measurements, maintenance, reports and records.

******End of Continuous Emissions Monitoring System (CEMS) Conditions******

Appendix B – Four-Factor Analyses and Control Determinations

NV Energy Four-Factor Analysis for Valmy and Tracy Generating Stations

March 18, 2024

Andrew Tucker
Nevada Division of Environmental Protection
Department of Conservation and Natural Resources
901 S. Stewart Street, Suite 4001
Carson City, NV 89701

RE: Regional Haze Reasonable Further Progress: Updated Four Factor Analysis for the NV Energy North Valmy and Tracy Generating Stations

Dear Andrew,

NV Energy is pleased to provide the attached Updated Four Factor Analysis for the NV Energy North Valmy and Tracy Generating Stations for Nevada Division of Environmental Protection review. The updated analysis reflects NV Energy's decision to pursue conversion of North Valmy Station from coal operation to natural gas operation and to continue operation of the Tracy Unit #6 - Piñon Pine #4 to address both energy and transmission system reliability considerations in Nevada.

We appreciate Nevada Division of Environmental Protection's support and look forward to further engagement to address any comments or questions.

Sincerely,

Mathew Johns
Vice President, Environmental Services and Land Management
NV Energy

cc: Ken McIntyre (kmcintyre@ndep.nv.gov)
Steven McNeese (smcneece@ndep.nv.gov)
Nicholas Schlafer (n.schlafer@ndep.nv.gov)
Andrew Tucker (atucker@ndep.nv.gov)
Chris Heintz (Christopher.Heintz@nvenergy.com)
Brigid McHale (Brigid.McHale@nvenergy.com)
Steve Jelinek (Steve.Jelinek@aecom.com)

Regional Haze Reasonable Further Progress: Updated Four Factor Analysis

NV Energy North Valmy and Tracy Generating Stations

AECOM Project Number: 60710366

Prepared for:

NV Energy
6226 W Sahara Ave
Las Vegas, NV 89146

Prepared by:

AECOM Technical Services, Inc.

250 Apollo Drive
Chelmsford, MA 01824

March 2024

1. Introduction

On August 12, 2019 the Nevada Division of Environmental Protection (NDEP), Bureau of Air Quality Planning notified NV Energy that it was developing a State Implementation Plan (SIP) for the Second Decadal Review period of the federal Regional Haze Program (42 USC §7491 – Visibility Protection for Federal Class I Areas). Among the goals of this program are a consideration of whether additional emission reductions at certain major sources are warranted to continue a reasonable rate of progress in visibility improvement. NDEP identified the North Valmy Generating Station and Tracy Generating Station as sources where further analysis is called for regarding the potential for additional controls for the targeted visibility impairment pollutants (nitrogen oxides, sulfur dioxide, and particulate matter).

As outlined in the regional haze rule, this analysis needs to first identify all technically feasible control options and then evaluate each relative to the following four statutory factors:

1) Cost of implementing emission controls,
2) Time necessary to install such controls,
3) Energy and non-air quality impacts associated with installing controls, and
4) The remaining useful life of the facility.

Accordingly, in March 2020 NV Energy prepared and submitted to NDEP Four Factor Analyses for Units 1 and 2 at the North Valmy Generating Station and all the generating units at the Tracy Generating Station. Over the next several years NV Energy worked with NDEP to provide additional information to address comments on these Four Factor analyses. During this process, NV Energy committed to shutting down and permanently ceasing operation of both Units 1 and 2 at North Valmy Station by December 31, 2028 and to shut down and permanently cease operation of Tracy Generating Station Piñon Pine Unit 4 by December 31, 2031. On August 12, 2022, NDEP submitted a revision to its State Implementation Plan (SIP) to EPA Region 9 to address regional haze considerations which concluded that:

- Both Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) are technically feasible alternatives for control of nitrogen oxide (NOx) emissions from North Valmy Units 1 and 2, however these alternatives are not cost effective considering the planned retirement date of these units,
- Both limestone- lime-based flue gas desulfurization systems are technically feasible alternatives for control of sulfur dioxide (SO_2) emissions from North Valmy Unit 1, as is the replacement of the existing hydrated lime-based Dry Sorbent Injection (DSI) system with a trona-based DSI system. None of these alternatives, however, are cost effective considering the planned retirement date of this unit,
- An upgrade to the existing flue gas desulfurization system on North Valmy Unit 2 is technically feasible but not cost effective considering the planned retirement date of this unit, and
- The installation of SCR to control NOx emissions from Tracy Station Piñon Pine Unit 4 was not reasonably cost-effective considering the planned retirement date for this unit.

However, changes in the energy landscape along with transmission system reliability considerations in Nevada necessitated reconsideration the intent to retire North Valmy Units 1 and 2 by December 31, 2028 and Tracy Generating Station Piñon Pine Unit 4 by December 31, 2031. In August 2023, NV Energy filed its Joint Application for approval of the Fifth Amendment to the 2021 Joint Integrated Resource Plan with the Public Utilities Commission of Nevada (PUCN). In part, the Fifth Amendment sought approval to convert the existing coal fueled plant at North Valmy Generating Station to a cleaner natural gas-fueled plant, and to continue operation of the North Valmy Station and Tracy Station Units 4 and 5 to 2049. Based in this filing, the state of Nevada partially withdrew portions of the State Implementation plan for Regional Haze to re-evaluate emission control measures that may be necessary to achieve reasonable progress during the second implementation period of the Regional Haze Rule in Nevada. In March 2024, the PUCN approved proceeding with these projects at North Valmy and Tracy Stations.

This report presents NV Energy's evaluation of the emissions rates and potential emission controls for the North Valmy and Tracy Generating Stations based on the revised future operating profile of each station. This report provides a description of the facilities (Section 2), a summary of the actions taken during the First Decadal Review period of the Regional Haze Rule (Section 3), a summary of the baseline emission rates for each of the generating units covered by this update (Section 4), and identification of potentially feasible control options and an assessment of each of the four statutory factors for feasible control options (Section 5). Section 6 presents a summary of the findings of this report. Appendices A and B provide the capital and annual cost estimates for alternative emission controls for each station. Appendix C provides further information about the approved cost of capital used by NV Energy to estimate the annualized cost of various emission control alternatives.

1.1 North Valmy Generating Station

1.1.1 Facility Description

The North Valmy Generating Station is an electric generating facility located at 23755 Treaty Hill Road in Valmy, NV, approximately 162 kilometers (km) southwest of the Jarbidge Wilderness Class I area in Elko County, NV.

The electric generating units at the facility currently consist of two coal-fired boilers that provide high pressure steam to steam turbine generators used to produce electricity.

Unit 1 at the North Valmy Station is a Babcock & Wilcox balanced draft, dry bottom, opposed wall-fired geometry boiler with a maximum allowable heat input rate when firing coal of 2,560 MMBtu/hr. The nominal net electric generating capacity of Unit 1 is 254 MW. The unit went into commercial operation in 1981, and it is currently equipped with a fabric filter baghouse to control particulate matter (PM) emissions and multi-stage combustion to control NOx emissions through the use of Low NOx coal-fired burners and overfired air. The unit is also equipped with a DSI system employing hydrated lime to control hydrogen chloride (HCl) emissions; this system also indirectly provides control of SO_2 emissions.

Unit 2 at the North Valmy Station is a Foster Wheeler balanced draft, dry bottom single wall-fired geometry boiler with a maximum heat input rate when firing coal of 2,881 MMBtu/hr. The nominal net electric generating capacity of Unit 2 is 268 MW. The unit entered commercial operation in 1985, and is equipped with a fabric filter baghouse to control PM emissions, multi-stage combustion (Low NOx coal-fired burners and overfire air) to control NOx emissions, and a lime slurry-based spray dryer to control SO_2 emissions.

NV Energy intends to convert both Unit 1 and Unit 2 at the North Valmy Generating Station from coal to natural gas firing upon State Implementation Plan approval and issuance of a permit modification. Subject to these approvals, NV Energy currently plans to convert one unit to natural gas firing in late 2025 and the second unit to natural gas firing in early 2026. This schedule will allow for one unit to be operational to meet system reliability needs during the conversion of the units and maintain availability for peak summer run conditions. Delays in permit approvals, supply chain, or similar considerations could potentially impact this expected conversion schedule. The electric generating capacity of each unit is expected to remain at their current levels following the conversion from coal to gas firing.

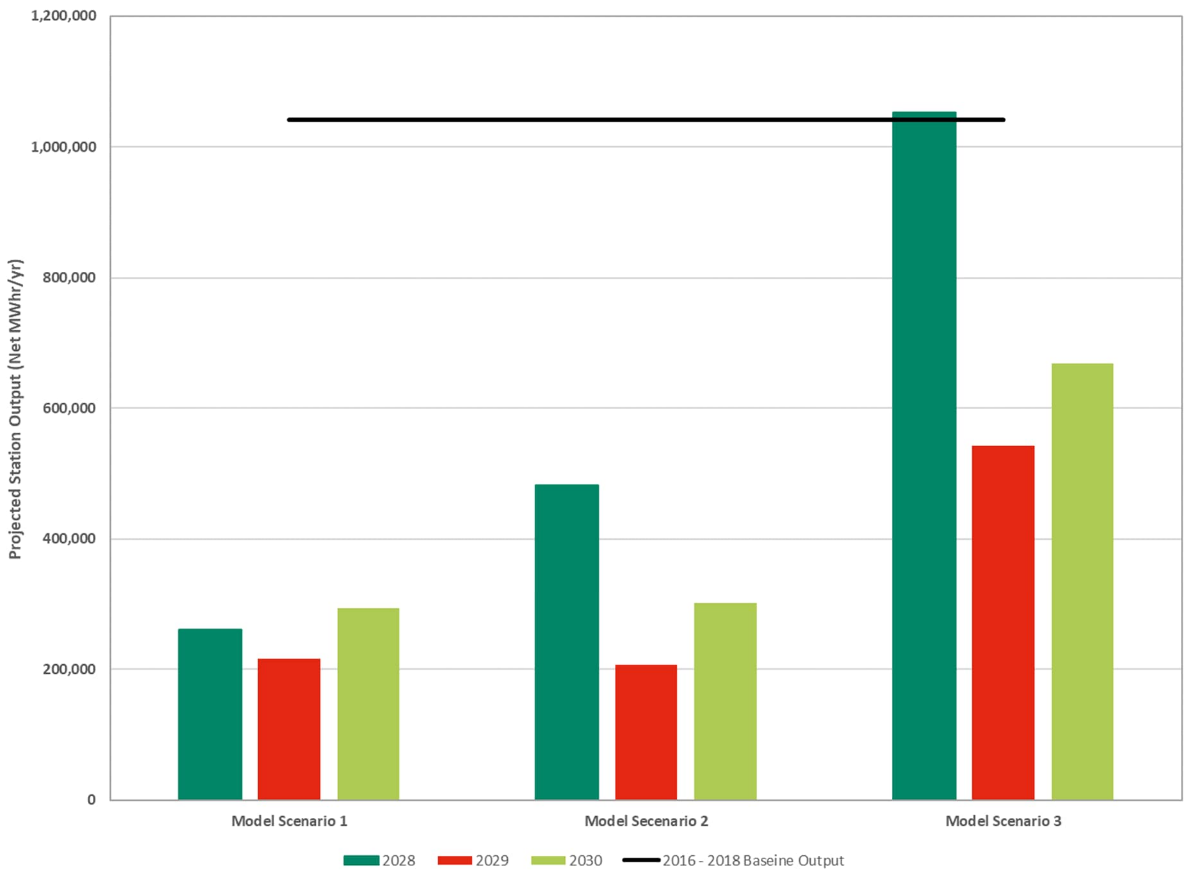
1.1.2 North Valmy Station Future Operating Profile

Section 3 (below) contains a summary of the actual heat input and emission rates reported from North Valmy Units 1 and 2 during the baseline period of January 1, 2016 to December 31, 2018. As explained further below, NV Energy considers this baseline operating profile to be representative of projected future operation of the Station following its conversion to natural gas firing.

Actual operations at North Valmy Station in recent years have been affected by lower demand due to the Covid pandemic in 2020. Subsequently, the higher natural gas prices experienced in 2021 and 2022 allowed for somewhat greater dispatch of Valmy on coal based on economic considerations. NV Energy anticipates that converting North Valmy Station to natural gas firing may allow for more flexibility in unit operations compared to operating the Station on coal. Current "must run" conditions at North Valmy are also expected to be somewhat reduced in the future with new transmission assets and resources being developed in the state to achieve Nevada's net-zero carbon goal by 2050.

NV Energy and Idaho Power are continually forecasting the output of their generating assets as part of Integrated Resource Planning by both companies. Accordingly, we have reviewed a range of resource planning modeling forecasts for North Valmy operations between 2028 and 2038 reflecting operation of the Station following its conversion to natural gas firing, including the period at end of the second decadal planning period (2019 – 2028). The results of three probable forecasts and a comparison to the Station's output experienced in 2016-2018 are presented in the following chart.

Figure 1 – North Valmy Generating Station – Projected Future Station Output



Model Scenario 3 assumes that no new generating resources would be located at Valmy as a conservative planning scenario, while other scenarios suggest that the station will experience lower operations. None of these forecasts, however, has the station's electrical output in 2028 – 2030 consistently higher than the average output the station generating in 2016 – 2018 (1,042,000 net MWhrs/yr).

Based on this information, NV Energy considers the actual output of the Station during the baseline 2016 – 2018 period to be conservatively representative of the projected output of the Station at the end of the second decadal review period. Accordingly, the baseline 2016 – 2018 electric generating rates for North Valmy Units 1 and 2 were used in conjunction with the projected net heat rates of the units following conversion to natural gas firing and US Environmental Protection Agency (EPA) emission factors for natural gas-fired boilers to estimate future projected NOx, SO_2, and particulate matter emissions for the purpose of assessing the economic feasibility of alternative emission controls for these units.

1.2 Tracy Generating Station

1.2.1 Facility Description

NV Energy's Tracy Generating Station is an electric generating facility located at 1799 Waltham Way, Exit 32, Sparks, Nevada approximately 81 kilometers (km) east of the Desolation Wilderness Class I area in El Dorado County, CA.

The electric generating units at the facility consists of a number of generating units. As stated previously, this revised Four Factor Analysis addresses only Tracy Unit 6, also known as Piñon Pine #4. Other units at this generating station that were addressed in the March 2020 Four Factor report are one conventional, pipeline natural gas-fired steam boiler (Tracy Unit 3); two pipeline natural gas and distillate-fired combustion turbines (Clark Mountain Units 3 and 4); and two pipeline natural gas-fired combined cycle units (CT/Duct Burner/HRSG Units 8 and 9).

Additionally, this facility formerly had two other pipeline natural gas and distillate fired boilers (Tracy Units 1 and 2) which were retired several years ago.

1.2.2 Tracy Generating Station Future Operating Profile

In March 2020 NV Energy prepared and submitted to NDEP a Four Factor Analysis for all the generating units at the Tracy Generating Station. Over the next several years NV Energy worked with NDEP to provide additional information to address comments on the Four Factor analysis. On August 12, 2022, NDEP submitted a revision to its State Implementation Plan (SIP) to EPA Region 9 to address regional haze considerations; this SIP revision concluded that the installation of SCR to control NOx emissions from Unit 4 was not reasonably cost-effective based on a shutdown date for Unit 4 of December 31, 2031 agreed to at that time, which limited the useful life/benefit for controls.

Consistent with information submitted by NV Energy to NDEP in response to comments received on the original Four Factor Assessment, NDEP concluded in its August 12, 2022 State Implementation Plan (SIP) submittal that the emissions associated with the 2016 – 2020 baseline operations at Tracy Station are representative of emissions from the predicted future operation of the station into the second decadal review period. Based on similar Resource Plan forecast modeling, NV Energy continues to expect that in the future the Station will operate at or below the average 2016 – 2020 baseline generation level (399,053 net MWhrs/yr). Using the same conditions used for Model Scenario 3 for North Valmy shown in Figure 1, the output forecast for Tracy Unit 6 - Piñon Pine #4 between 2028 and 2030 is 158,000 to 224,000 net MWhrs/yr, which is less than the unit's average generation level from 2016 – 2020.

Consequently, NV Energy continues to believe that the actual output of Tracy Unit 6 - Piñon Pine #4 during the baseline 2016 – 2018 period is conservatively representative of the projected output of the Station at the end of the second decadal review period. Therefore, this operating level was used to assess the economic feasibility of alternative emission controls for this unit.

Section 5.2 of the revised Four Factor Analysis was prepared to re-evaluate controls for Unit 6 - Piñon Pine #4 based on the assumption of its continued operation. Additionally, this section also incorporates the relevant issues addressed in the several responses to comments with NDEP after submittal of the 2020 Four Factor Analysis.

2. First Regional Haze Planning Period Reasonable Progress Determination

2.1 North Valmy Station

Neither Unit 1 nor Unit 2 at the North Valmy Station were subject to analysis during the First Decadal Review period, since per the Regional Haze Rule (i.e., 40 CFR 51 §§308) only units that were in existence during the Best Available Retrofit Technology (BART) applicability window (that is, between August 7, 1962 and August 7, 1977) were eligible for consideration for BART emission controls during this review period. Neither Unit 1 nor Unit 2 at North Valmy Station were operating during the BART applicability window.

2.2 Tracy Station

Only Units 1, 2, and 3 at Tracy Station were subject to BART review during the First Decadal Review period. They were the only units that had been in existence at the Station during the BART applicability window. The BART conclusions during the First Decadal Review period led to a requirement to add controls to all three of these units. Units 1 and 2 were permanently retired. Low-NOx burners and the elimination of oil firing were determined to be representative of BART for Unit 3; these controls were implemented and this unit remains in operation.

3. Baseline Emissions Summaries

3.1 North Valmy Generating Station

The following table summarizes the heat input rates for each unit and emission rates for the three visibility-impairing pollutants from the two units at the North Valmy Generating Station during the baseline period for this assessment. As previously discussed with the NDEP, the baseline period encompasses the 2016 through 2018 calendar years.

Table 1 – North Valmy Generating Station – 2016-2018 Heat Input and Emissions Rates

	Heat Input (MMBtu/yr)	Baseline Emission Rates (ton/yr)		
		SO_2	NOx	PM
North Valmy Unit 1				
2016	4,862,104	1,848	797	22.01
2017	3,254,125	1,232	587	16.27
2018	6,169,957	2,357	1,027	27.76
2016 – 2018 Average	4,772,062	1,812 (0.760 lb/MMBtu)	804 (0.337 lb/MMBtu)	22.01 (0.0092 lb/MMBtu)
North Valmy Unit 2				
2016	5,484,226	431	839	54.84
2017	4,194,914	356	674	20.97
2018	9,298,082	716	1,493	37.16
2016 – 2018 Average	6,325,741	501 (0.158 lb/MMBtu)	1,002 (0.317 lb/MMBtu)	37.67 (0.0119 lb/MMBtu)

Table 2 summarizes what the projected average emission rates from North Valmy Units 1 and 2 would have been during the baseline period had the units been converted to natural gas firing at that time. These estimates utilize the average electric generating rate for each unit, each unit's projected net heat rate following conversion to natural gas firing, and US EPA emission factors from the latest revision of AP-42: Compilation of Air Emission Factors, Section 1.4 for natural gas-fired boilers. For the NOx emission estimates, the projected emission rates following conversion to natural gas firing assume that Units 1 and 2 would be equipped with new Low NOx natural gas-fired burners with an emission rate of 0.137 lb/MMBtu because the current burners employed on the units to burn coal are not designed to be fired with natural gas.

Table 2 – North Valmy Generating Station – Estimated Emissions Rates Associated with Natural Gas Firing

	Estimated SO_2 Emissions (ton/yr)	Estimated NOx Emissions (ton/yr)	Estimated PM Emissions (ton/yr)
Unit 1	1.48	344.6	18.71
Unit 2	1.96	457.8	24.85

The estimated emission rates presented in Table 2 illustrate that converting North Valmy Units 1 and 2 to natural gas firing will result in significant reductions in all visibility-impairing pollutants: over 99% reduction in SO_2 emissions, 56% reduction in NOx emissions, and 27% reduction in PM emissions compared to the 2016-2018 baseline values.

3.2 Tracy Generating Station

Table 3 below summarizes the baseline emissions (2016-2020 average) for the three visibility-impairing pollutants from the Tracy Unit 6 - Piñon Pine #4. For the reasons described in Section 1.2.2, these emissions are a reasonable basis to project future emissions if no additional controls are implemented.

Table 3 – Tracy Piñon Pine #4 – Average 2016-2020 Emissions from Combustion Source

Unit ID	NV Energy ID	Description (and Nominal Rating)	Current Controls	Average NOx Emissions ton/yr	Average SO_2 Emissions ton/yr	Average PM_{10} Emissions ton/yr
Unit 6	Piñon Pine 4	GE 6FA NG Combined Cycle Combustion Turbine 107 MW (+ 23 MW Duct Burners)	Low NOx combustors & steam injection	250	1.0	12.4

Note: This five-year baseline period was requested by NDEP for this Tracy unit because of variability in loads not fully represented by a shorter baseline.

4. Identification of Potentially Feasible Emission Controls

The first step in a four-factor analysis is to identify emission controls options that have the potential to be feasible for each source and result in meaningful emission reductions. This section presents an evaluation of the technical feasibility of potential control options for the emission sources at the North Valmy Generating Station following the conversion of Units 1 and 2 to natural gas firing, as well as the feasibility of potential control options for Piñon Pine #4 at the Tracy Generating Station. Section 5 continues their analysis by evaluating each option relative to the statutory four factors (cost, timing, other Impacts, and remaining useful life).

4.1 North Valmy Generating Station

4.1.1 Sulfur Dioxide and Particulate Matter Emission Control Options

Following the conversion of North Valmy Units 1 and 2 to natural gas firing, there will be no technically feasible add-on control options for SO_2 or PM emissions from these sources. NV Energy concludes that converting North Valmy Units 1 and 2 from coal to natural gas firing constitutes reasonable progress towards achieving regional haze reduction goals with respect to SO_2 and PM emissions.

4.1.2 Nitrogen Oxides Emission Control Options

Selective Non-catalytic Reduction (SNCR), Selective Catalytic Reduction (SCR), and flue gas recirculation (FGR) were evaluated as technically feasible options on North Valmy Units 1 and 2 following the conversion of these units to natural gas firing. No other technically feasible NOx control options were identified for these units.

SNCR has been applied to control NOx from a wide range of combustion sources burning a variety of fuels. With this alternative, NOx produced by fuel combustion is converted to elemental nitrogen and water by the thermally-initiated chemical reduction reaction with a reducing agent (urea or ammonia) at temperatures between 1,600°F and 2,100°F. In the SNCR process, the combustion unit acts as the reaction chamber, and the reducing agent is injected into the unit where combustion gas is within the required temperature range and where there is sufficient residence time and adequate flue gas mixing. The SNCR process does not require a catalyst to achieve contact between NOx and the reducing agent. An excess of reducing reagent is typically required to be injected in applications where high NOx control efficiencies are required or if inlet NOx emission rate is low.

In the SCR process, the chemical conversion of NOx to nitrogen and water occurs via the use of a catalyst to promote reducing agent utilization at a lower operating temperature than with SNCR. The preferred flue gas temperature range within the catalyst is 650 °F to 725 °F.

FGR has been used to reduce thermal NOx formation in large coal-, oil-, and natural gas-fired boilers. With this alternative, a portion (10% to 30%) of the boiler’s flue gas is recycled back to the main combustion chamber by removing it from the stack or breeching using a recirculation fan and mixing it with the primary air or secondary air prior to be being fed to the burners. The recirculated flue gas reduces the flame temperature and oxygen concentration in the boiler's combustion zone, thus reducing thermal NOx formation. Some operational problems can occur with FGR, including burner flame instability and loss of combustion and heat exchanger efficiency. The amount of recirculated flue gas is the key operating parameter influencing the NOx emission rate achievable with this alternative. In retrofit situations, the boilers must have compatible and adequate ancillary equipment and the FGR system must be individually engineered and designed. The degree of NOx reduction that can be achieved using FGR in retrofit situations depends on specific characteristics of a boiler's operating profile; since FGR reduces NOx more efficiently when a boiler is operating at high load, this alternative may have limited effectiveness for boilers that operate at low loads.

As noted above, converting North Valmy Units 1 and 2 to natural gas firing and the installation of new natural gas-fired Low NOx Burners is expected to result in substantial reductions in NOx emissions compared to their current emissions profile. Installation of FGR or SNCR following the conversion to gas firing are nonetheless technically feasible alternatives to further reduce NOx emissions. However, the relatively low NOx emission rate associated with the use of natural gas-fired Low NOx Burners would be expected to limit the achievable emissions reduction rate with either FGR or SNCR.

Based on information presented by the Arizona Department of Environmental Quality (ADEQ) in their October 2015 revision to their Regional Haze Implementation Plan to address the conversion of certain units at Arizona Public Service's Cholla Generating Station from coal firing to natural gas firing[1], the estimated NOx control performance of SNCR is estimated at 25% (to an emission rate of 0.103 lb/MMBtu) following conversion of North Valmy Units 1 and 2 to natural gas firing. The specific level of NOx reduction achievable with FGR on North Valmy Units 1 and 2 has not yet been definitively established at this point since the design engineering for conversion of these units to natural gas firing has only recently been initiated. Preliminary information received from prospective equipment suppliers, however, suggests that a level of NOx reduction comparable to that which could be achieved using SNCR may be achievable with FGR.

Equipping North Valmy Units 1 and 2 with SCR would be expected to reduce their controlled NOx emission rate to 0.03 lb/MMBtu, or a reduction in NOx emissions of 78% compared to the use of Low NOx natural gas burners alone. The expected reduction in NOx emissions associated with SCR is consistent with the midpoint of the range of actual SCR control efficiencies achieved in practice (70 – 90%) presented in Section 4.2, Chapter 2 of EPA's Control Cost Manual.

[1] "Arizona State Implementation Plan – Revision to the Arizona Regional Haze Plan for Arizona Public Service Cholla Generating Station," October 2015.

4.2 Tracy Generating Station

4.2.1 Sulfur Dioxide and Particulate Matter Control Options

Tracy Piñon Pine #4 currently burns only pipeline natural gas as its fuel. The use of pipeline natural gas fuel in this generating unit minimizes SO_2 and PM emissions. There are no further emissions controls for these pollutants that are technically feasible.

4.2.2 Nitrogen Oxides Emission Control Options

Tracy Piñon Pine #4 is a GE 6FA natural gas-fired turbine operating with a heat recovery steam generator (HRSG) in combined cycle mode. It is rated at a heat input rate of 763.9 MMBtu/hr with duct burners rated at 156.5 MMBtu/hr. The unit was constructed in 1996 and was originally permitted as part of a coal gasification project. This unit is equipped with GE's gasification compatible combustion system designed to accommodate a wide spectrum of low heating value fuels, including gasified coal. However, the unit now only fires clean pipeline natural gas. The turbine uses steam injection to partially quench the heat of combustion to control NOx emissions to approximately 41 ppm at 15% O_2 (2016-2020 average).

Additional NOx controls that are technically feasible for this unit would be a combustor conversion to the latest GE dry low NOx (DLN) combustor (replacing the current steam injection) or installation of SCR. Selective non-catalytic reduction is not technically feasible for a combustion turbine because the exhaust temperatures are too low.

<u>Dry Low NOx Combustor</u>
GE offers a lean premixed Dry Low NOx combustor system capable of better performance than steam injection for pipeline natural gas-fired turbines. GE's DLN combustor pre-mixes the gaseous fuel and compressed air to avoid local zones of high temperatures where elevated levels of NOx would form. The DLN combustor becomes an intrinsic part of the turbine and works with its design to minimize NOx. DLN performance varies depending on the specific turbine, but typically ranges from 9 to 25 ppm operating on pipeline natural gas. For the GE 6FA turbine, conversion to DLN combustors would lower NOx emissions to about 15 ppm (at 15% O_2), a 60% decrease.

<u>Selective Catalytic Reduction (SCR)</u>
Described above in Section 4.1.2, SCR can be used as an add-on control technology for a combustion turbine. In a turbine's exhaust, the SCR system needs to be located in the exhaust path at a location where the temperature of the exhaust gas matches the operating temperature of the catalyst; for conventional SCR catalyst, this is typically about 600°F to 750°F. For a combined cycle turbine, the exhaust gas at this temperature is in the middle of the HRSG.

For this turbine, the existing HRSG appears to have room to accommodate the SCR catalyst, in a reasonable temperature range, after the high pressure superheater steam coils and before the economizer and various low-pressure steam coils. For this turbine, the exhaust gas temperature at this location is approximately 793°F, which is a little higher than optimal for SCR, but still acceptable. SCR requires on-site storage of ammonia, a hazardous chemical, and causes approximately 5 ppm ammonia "slip" emissions from unreacted ammonia. Typically, SCR can reduce NOx between 70% and 90% depending on the design and uniformity of conditions in the exhaust. SCR in this turbine with the existing combustor could lower NOx approximately 90% to approximately 4 ppm (at 15% O_2).

Retrofitting the turbine with a DLN combustor system or installing SCR are both technically feasible NOx alternatives for Tracy Piñon Pine #4 and are evaluated further in Section 6 relative to the Regional Haze Rule's four factors.

5. Four Factor Analysis

5.1 North Valmy Generating Station

The previous section presented an analysis of the control alternatives that are potentially feasible to lower the emissions of NOx from the emission units at the North Valmy Generating Station. The control options identified for further evaluation to reduce regional haze for these units are as follows:

North Valmy Unit 1 Potential NOx Control Options:

- Selective Non-Catalytic Combustion (SNCR),
- Flue Gas Recirculation (FGR), and
- Selective Catalytic Reduction (SCR).

North Valmy Unit 2 Potential NOx Control Options:

- Selective Non-Catalytic Combustion (SNCR),
- Flue Gas Recirculation (FGR), and
- Selective Catalytic Reduction (SCR).

The above two emission units and their potential control options are analyzed in this section relative to the four statutory factors listed in the regional haze rules which are:

1) Cost of implementing emissions controls,
2) Time necessary to install such controls,
3) Energy and non-air quality impacts associated with installing controls, and
4) The remaining useful life of the facility.

5.1.1 Cost of Implementing Controls

5.1.1.1 *NOx Controls - North Valmy Unit 1*

As noted above, FGR, SNCR and SCR are all technically feasible alternatives for reducing NOx emissions from this source following conversion of North Valmy Unit 1 to natural gas firing.

The capital and annualized operating costs for SNCR for Unit 1 were estimated using the SNCR Cost Calculation Spreadsheet in EPA's Control Cost Manual[2]. A retrofit factor of 1.0 was used for this unit based on the assumption that retrofit of SNCR on this unit would likely be relatively straightforward.

[2] EPA Air Pollution Control Cost Manual, Section 4 (NOx Controls) Chapter 1: "Selective Noncatalytic Reduction," April 2019

Similarly, the capital and annualized costs for SCR were estimated using the SCR Cost Calculation Spreadsheet in EPA's Control Cost Manual[3]. Considering the constraints on available space to locate equipment in the vicinity of Unit 1, the need for new steel structures to be built to support the SCR equipment, and the need for large-capacity ductwork to be installed between the unit's existing economizer outlet to the external SCR reactor and between the SCR reactor and the existing air preheaters, a higher than average retrofit cost for this alternative might be required. For the purposes of this assessment, however, a retrofit factor of 1.0 was utilized to estimate the capital cost of SCR for Unit 1.

The estimated capital cost to retrofit an FGR system on Unit 1 is based on budgetary equipment costs provided by a prospective equipment vendor. Estimated annual costs for this alternative include capital recovery charges, additional parasitic electrical charges for the recirculation fan, and additional fuel charges associated with the heat rate penalty resulting from decreased combustion efficiency.

For annualization of the capital cost for each alternative, the remaining useful life/plant life was set as 30 years beyond the emission control system installation date. This estimated useful equipment life is conservative since the currently-projected retirement date of the Station is 2049 (i.e., 24 years after conversion of North Valmy Unit 1 to natural gas firing). A rate of 6.95% was used to annualize the capital cost of each alternative. This is NV Energy's current firm-specific overall cost of capital approved by the PUCN in the most recent general rate case. Further details explaining the basis of this rate is provided in Appendix C.

Table 4 summarizes the estimated capital and annual costs for the alternative NOx control methods for Unit 1. Details of these cost estimates are provided in Appendix A.

[3] EPA Air Pollution Control Cost Manual, Section 4 (NOx Controls) Chapter 2: "Selective Catalytic Reduction," June 2019

Table 4 – North Valmy Unit 1 - NOx Control Option Cost Summary

Selective Non-Catalytic Reduction	
Estimated Capital Cost	\$7.89 million
Annual Capital Recovery	\$0.63 million/yr
Annual Operating Cost	\$0.21 million/yr
Total Annual Cost	\$0.84 million/yr
NOx Emission Rate with SNCR	258.5 tons/yr
NOx Emission Reduction with SNCR	86.2 tons/yr
SNCR Cost Effectiveness	\$9,740/ton
Flue Gas Recirculation	
Estimated Capital Cost	\$3.53 million
Annual Capital Recovery	\$0.28 million/yr
Annual Operating Cost	\$0.56 million/yr
Total Annual Cost	\$0.84 million/yr
NOx Emission Rate with FGR	258.5 tons/yr
NOx Emission Reduction with FGR	86.2 tons/yr
FGR Cost Effectiveness	\$9,801/ton
Selective Catalytic Reduction	
Estimated Capital Cost	\$34.6 million
Annual Capital Recovery	\$2.77 million/yr
Annual Operating Cost	\$0.76 million/yr
Total Annual Cost	\$3.53 million/yr
NOx Emission Rate with SCR	75.3 tons/yr
NOx Emission Reduction with SCR	269.3 tons/yr
SCR Cost Effectiveness	\$13,122/ton

Following conversion of Unit 1 to natural gas firing, the estimated cost effectiveness of both SNCR and FGR are below \$10,000 per ton controlled, which NV Energy understands the NDEP considers to be reasonable in the context of making progress towards the goals of the Regional Haze Rule. The cost effectiveness of installing SCR on Unit 1, however, is estimated to exceed this \$10,000 per ton controlled threshold.

Based on the preliminary information available at this stage of the engineering design associated with converting North Valmy Unit 1 to natural gas firing, it appears that the capital cost impact to install FGR on the unit may be lower than the capital cost to install SNCR, as shown in Table 4. The annualized cost impact and annual NOx reduction rate associated with these two alternatives, however, are currently estimated to be similar. Consequently, a conclusion as to which alternative meets the reasonable further progress goals for the least cost cannot be reached at this point in time.

As noted above, the currently anticipated retirement date of the North Valmy Station units is 2049, or between 23 and 24 years following conversion of each unit to natural gas firing. While this is less than the remaining useful life assumptions assumed for each emission control alternative, the use of a shorter useful life for these controls has no material effect on each alternative's the cost effectiveness conclusion. Appendix A contains a table that compares the estimated cost effectiveness of each NOx control alternative using useful equipment lives of 30 and 25 years.

5.1.1.2 *NOx Controls - North Valmy Unit 2*

As noted above, FGR, SNCR and SCR are all technically feasible alternatives for reducing NOx emissions from Unit 2. As with the cost estimates developed for Unit 1 (described above), capital and annualized operating costs for SNCR for Unit 2 were estimated using EPA's Control Cost Manual and applying a retrofit factor of 1.0. Capital and annual cost for FGR on Unit 2 were estimated as described above in Section 5.1.1.1 for Unit 1 using preliminary budgetary cost information provided by a prospective equipment vendor. Capital and annualized costs for SCR were estimated as described above for Unit 1 using EPA's Control Cost Manual and also employing a retrofit factor of 1.0. As with Unit 1, the remaining useful life/plant life was conservatively set as 30 years beyond the emission control system installation date for annualization of the capital cost for each alternative, recognizing that the unit may be retired sooner than 30 years based on an anticipated 2049 retirement date. Cost effectiveness for each alternative was estimated using the projected station output and corresponding uncontrolled emission levels associated with the 2028 projection.

Table 5 summarizes the estimated capital and annual costs for these control methods. Details of these cost estimates are provided in Appendix A.

Table 5 – North Valmy Unit 2 - NOx Control Option Cost Summary

Selective Non-Catalytic Reduction	
Estimated Capital Cost	$8.42 million
Annual Capital Recovery	$0.68 million/yr
Annual Operating Cost	$0.24 million/yr
Total Annual Cost	$0.92 million/yr
NOx Emission Rate with SNCR	343.3 tons/yr
NOx Emission Reduction with SNCR	114.4 tons/yr
Control Cost Effectiveness	$8,018/ton
Flue Gas Recirculation	
Estimated Capital Cost	$3.53 million
Annual Capital Recovery	$0.28 million/yr
Annual Operating Cost	$0.71 million/yr
Total Annual Cost	$1.00 million/yr
NOx Emission Rate with FGR	343.3 tons/yr
NOx Emission Reduction with FGR	114.4 tons/yr
FGR Cost Effectiveness	$8,712/ton
Selective Catalytic Reduction	
Estimated Capital Cost	$37.1 million
Annual Capital Recovery	$2.97 million/yr
Annual Operating Cost	$0.93 million/yr
Total Annual Cost	$3.90 million/yr
NOx Emission Rate with SCR	100.0 tons/yr
NOx Emission Reduction with SCR	357.7 tons/yr
Control Cost Effectiveness	$10,903/ton

As with Unit 1, the cost effectiveness of utilizing either SNCR or FGR on North Valmy Unit 2 is estimated to be below the NDEP threshold for reasonable further progress of $10,000 per ton of NOx controlled, while the cost effectiveness of SCR is estimated to exceed this threshold. Per Table 5 the capital cost to install SNCR on the unit may be lower than the cost to install FGR but a conclusion about which alternative has the lower overall cost to achieve the reasonable further progress goals cannot be determined at this stage of the engineering design effort.

5.1.2 Time Necessary to Install Controls

State Implementation Plans (SIPs) that address emission reductions needed to achieve regional haze improvements were originally due to EPA by July 21, 2021. NV Energy understands that NDEP transmitted its SIP submittal to EPA Region 9 on August 12, 2022, however NV Energy's reconsideration of its plans with respect to the conversation of North Valmy Units 1 and 2 warrant a reconsideration of the conclusions presented in that SIP submittal.

Nonetheless, sources are not expected to begin implementation of any additional mandated controls until after the state's SIP has been approved by US EPA. As discussed in Section 1.1.1, NV Energy intends to convert both Unit 1 and Unit 2 at the North Valmy Generating Station from coal to natural gas firing upon State Implementation Plan approval and issuance of a permit modification. Subject to these approvals, conversion on one unit would occur as soon as late 2025 followed by the second unit in early 2026, allowing for one unit to be operational to meet system reliability needs during the conversion of the units and maintain availability for peak summer run conditions. Delays in permit approvals, supply chain, or similar considerations could potentially extend this time. Understanding these potential constraints, it is still reasonably anticipated that compliance with any mandated reduction in NOx emissions at North Valmy Station would be achieved before the fourth quarter of 2028 (the end of the Second Decadal Review period).

5.1.3 Energy and Non-air Quality Impacts of Controls

Both SNCR and SCR utilize some form of ammonia as a reagent to promote the conversion of NOx to elemental nitrogen and water. As a result of imperfect mixing between the flue gas and the reagent, a greater than stoichiometric amount of reducing agent must be injected for the NOx reduction target to be achieved. The excess ammonia remains unreacted in the process and is emitted out the stack as ammonia "slip". Ammonia emissions associated with either SCR or SNCR are typically between 2 to 10 ppm. Ammonia is a hazardous air pollutant but is not considered harmful at this level. Ammonia for these processes can be provided using either anhydrous ammonia, aqueous ammonia or urea. Storage and use of these forms of ammonia, especially anhydrous ammonia, can have significant safety concerns. Facilities that use aqueous ammonia solution at concentrations greater than 20% are subject to additional accident prevention and emergency response plan development requirements under Nevada's Chemical Accident Prevention Program. Consequently, the maximum allowable concentration of ammonia in aqueous solutions used at NV Energy facilities is 19%. With proper system design and operation, the safety issues associated with this material are considered manageable.

Retrofitting FGR or SCR to either North Valmy Unit 1 or 2 would be expected to result in an increase in the parasitic electrical load of the station. As described above, FGR systems require the use of an additional fan to carry boiler flue gas from the stack or breeching back to the combustion zone of the boiler. SCR systems require that auxiliary power be supplied to dilution fans for mixing air with the ammonia reducing agent and to pump ammonia across the vaporizer. In addition, placement of the SCR catalyst grid in the exhaust flow path of the boiler causes backpressure which must be overcome by supplying additional power to the existing flue gas fan systems. These energy use increases are reflected in the economic analysis as one of the operating costs for FGR and SCR.

The increased energy use, water use, and waste generation have all been accounted for in the economic assessment of these alternatives summarized previously.

5.1.4 Remaining Useful Life of the Facility

As mentioned previously, for the purposes of the economic analysis it has been assumed that both North Valmy Unit 1 and Unit 2 continue to operate at least 30 years after any of the technically feasible control alternatives were to be implemented, recognizing that the unit may be retired sooner than 30 years based on 2049 being the currently-anticipated retirement date of the Station. The 30-year life of the control device is a typical assumption for these types of controls in this analysis unless the expected life of the source itself is notably shorter.

5.1.5 Additional Considerations

In addition to the mandated factors delineated above, NV Energy notes that EPA modeling results indicate that that by the end of the Second Decadal Review period (2028), anthropogenic-related haze at the Jarbidge Wilderness Area will represent only a very small portion of total haze. Furthermore, EPA's modeling shows that electric generating units will contribute only about 6% of the total anthropogenic haze, which means that emissions from electric generating units will have only a very small contribution to total haze at Jarbidge. Also, based on the baseline (2016 – 2018) emissions, the adjusted glidepath indicates that the 2028 visibility goal has already been achieved at the Jarbidge Wilderness Area. As noted in Section 3.1, simply converting the Station to gas firing is expected to reduce SO_2 emissions by more than 2,300 tons/yr and NOx emissions by over 1,000 tons/yr; these reductions alone suggest that reasonable progress goals will likely be met by the target date even if no additional emission controls were to be installed on the North Valmy Station in conjunction with the conversion.

5.2 Tracy Power Generating Station

Section 4.2 presents a summary of the control technologies that are potentially feasible to lower NOx emissions from the Unit 6 - Piñon Pine #4 at the Tracy Generating Station. The identified control options for further evaluation are as follows:

Unit #6 (Piñon Pine #4 Combined Cycle Turbine with Steam Injection) Potential Control Options:

- Retrofit with GE Dry Low NOx (DLN) 2.6 Combustors (achieves 15 ppm NOx);
- Selective Catalytic Reduction (SCR) (achieves 90% reduction in NOx (4.1 ppm at 15% O_2); or
- Both SCR and DLN (achieves 2 ppm NOx).

This emissions unit and its potential control options are analyzed in this section relative to the four statutory factors listed in Section 5.1.

5.2.1 Cost of Implementing Controls

The Tracy Unit #6 could be retrofitted with either lean premix dry low NOx (DLN) combustors or with SCR. Additionally, the turbine could theoretically be retrofitted with both DLN and SCR. These control options are technically feasible for reducing NOx on this source. NV Energy has estimated the capital and annual operating costs associated with these NOx control options. These costs are discussed and summarized in the following sections.

DLN Combustor Costs: The capital costs for a DLN conversion are based on a 2010 budgetary estimate provided by General Electric (GE) for a DLN 2.6 combustor retrofit specific to this turbine. GE verified to NV Energy that this estimate was currently still valid after adjusting for inflation. This GE DLN equipment cost estimate was escalated to 2024 dollars using the Chemical Engineering Plant Cost Index (CEPCI) as recommended in US EPA's cost manual. Installation and other direct and indirect capital costs were based on GE's estimates or standard factors from US EPA cost manual and are also in 2024 dollars.

GE estimates that this turbine's electrical generating capacity will decrease approximately 3.5% with DLN combustors verses the current steam injection. NV Energy has a responsibility to have available capacity to meet system demands and would need to compensate for this lost generating capacity by purchasing capacity externally. The conversion also decreases the efficiency of the turbine - which requires more fuel use to generate the same electricity. However, not using steam injection saves fuel use. To estimate the net overall cost impacts of these factors, NV Energy's Resource Planning Department used the PROMOD software model to estimate the changes in operating costs associated with these impacts of a DLN conversion. This software model incorporates numerous variables such as operating unit characteristics, system operating demand, etc. to analyze scenarios for decision making and planning purposes. As described in Section 6.2 of the original Four Factor Analysis for the Tracy Station submitted to NDEP in March 2020, the PROMOD modeling estimated that the total operating cost impacts would be approximately $680,000/yr for the DLN conversion.

There are other types of operating costs associated with conversion of this unit to DLN burners which NV Energy has not quantified, and if included, would further increase the costs of this control option. These include increased costs from the discontinuation of steam injection which hurts the plant's water balance.

Details of the above described estimated DLN Combustor conversion cost are included in Appendix B – Tables B-1 and B-2.

SCR Costs: As described in Section 6.2 of Tracy's original Four Factor Analysis, the capital cost estimate for SCR for this turbine is based on a detailed price proposal provided to NV Energy in December 2019 by an SCR vendor, CECO Environmental/Peerless Manufacturing Co. The vendor's cost proposal covers the equipment costs for the SCR retrofit, ammonia injection skid, and ammonia storage. An estimated cost for installation was also included. NV Energy additionally estimated the costs of ancillary equipment not in the vendor's quote and indirect installation costs using standard factors in US EPA's Control Cost Manual SCR chapter. SCR capital costs were escalated to 2024 dollars using the CEPCI index.

Annual operating costs associated with the use of SCR are based on the methodologies in the US EPA Control Cost Manual SCR chapter and also account for the capacity loss costs associated with a derate of the turbine due to the additional pressure drop caused by the SCR catalyst. The costs of SCR have been estimated both as a standalone option without DLN Burners (e.g., SCR with existing steam injection) and combined with Dry Low NOx Combustor.

Details of the above-described SCR cost are included in Appendix B – Tables B-3 through B-6.

Both SCR and DLN Costs: SCR and DLN could both be implemented together. The capital cost for this scenario is merely the sum of the two separate capital costs. Similarly, most of the operating costs are additive except for two categories.

1) SCR catalyst changeout costs are assumed to be 50% less frequent because the DLN will lower the SCR inlet NOx levels, and

2) Reagent (ammonia) usage is assumed to be 65% lower with DLN because of the lower inlet NOx.

A summary of these operating cost differences is summarized in Appendix B Table B-7.

The below tables summarize these capital and operating costs and the NOx emissions reduction expected for each control option.

Table 6 – Tracy Unit #6/Piñon Pine 4 - NOx Control Options Cost-Effectiveness

Dry Low NOx Combustor Conversion	
Estimated Capital Cost	\$18.27 million
Annual Capital Recovery (30 yr life)	\$1.47 million
Annual Operating Costs	\$0.68 million
Total Annual Costs	\$2.15 million/yr
Est. Annual Emission Rate with DLN	91.5 tons/yr
NOx Emission Reduction	158.5 tons/yr
Control Cost Effectiveness	\$13,535/ton

Selective Catalytic Reduction (with existing steam injection)	
Estimated Capital Cost	\$11.99 million
Annual Capital Recovery (30 yr life)	\$0.94 million
Annual Operating Costs	\$0.42 million
Estimated Annual Cost	\$1.36 million/yr
Est. Annual Emission Rate with SCR	25.0 tons/yr
NOx Emission Reduction	225 tons/yr
Control Cost Effectiveness	\$6,053/ton

Selective Catalytic Reduction (with DLN Combustor)	
Estimated Capital Cost	\$30.27 million
Annual Capital Recovery (30 yr life)	\$2.41 million
Annual Operating Costs	\$0.97 million
Estimated Annual Cost	\$3.38 million/yr
Est. Annual Emission Rate with SCR	12.1 tons/yr
NOx Emission Reduction	237.8 tons/yr
Control Cost Effectiveness	\$14,229 / ton
Increm. Cost Effect. vs just SCR	\$157,812 / ton

For annualization of the capital cost, the remaining useful life/plant life was conservatively assumed to be 30 years beyond the DLN or SCR installation date, recognizing that the unit may be retired sooner than 30 years based on 2049 being the currently-anticipated retirement date of the Tracy Station. As explained in Section 5.1.1.1, NV Energy's firm-specific cost of capital of 6.95% as established by the PUCN was used to annualize the capital cost estimates.

Retrofitting this existing turbine with a new DLN combustor system is very expensive with an average cost-effectiveness over \$13,500 per ton. The major cost element is the capital cost for the DLN combustor upgrade itself which costs over $18 million dollars capital. NV Energy does not consider this to be a reasonably cost-effective control relative to the environmental benefit. It may seem unexpected that DLN combustor would not be cost effective given that newest turbines already come with DLN combustors to minimize NOx. This is because it is more expensive to retrofit a DLN combustor onto an existing turbine than it is to equip a new turbine with this technology. The cost of the combustor and fuel system is a major component of the turbine and a large part of its costs. However, when building a new turbine, the cost difference for a DLN combustor compared to a conventional combustor is relatively. For Pinon Pine #4 the cost to remove the existing combustor and replace it with a new DLN combustor is higher than cost to simply add an SCR system to the existing turbine. Moreover, replacing the existing combustor with a DLN combustor would provide less NOx reduction than the installation of SCR.

Installing SCR is a less expensive option than the DLN conversion and provides a greater level of NOx reduction. The cost to install SCR is somewhat less expensive than it might otherwise be because the existing HRSG has room within its physical structure to add SCR catalyst modules. Even so, the cost for this control option is nearly $12 million in capital costs and total annual costs of over $1.3 million per year including capital recovery. This results in a cost-effectiveness of adding SCR based on a 30-year equipment life of approximately $6,000. NV Energy understands that NDEP considers this cost-effectiveness reasonable in the context of making progress towards the goals of the Regional Haze Rule.

The final NOx control option would be the implementation of both the SCR and the DLN conversion. Although this provides a slight additional NOx reduction versus the SCR w/steam injection control option, it would have extremely higher costs as shown above. The SCR w/DLN option's incremental cost relative to the incremental benefit is clearly prohibitive with an average cost-effectiveness over $14,000/ton and an incremental cost effectiveness (vs SCR alone) of over $157,000 per incremental ton of NOx controlled.

Based on the NOx control options evaluated, installing SCR was the only option for Unit #6 - Piñon Pine #4 that NV Energy understands NDEP considers this cost-effectiveness reasonable in the context of making progress towards the goals of the Regional Haze Rule.

5.2.2 Time Necessary to Install Controls

As described in Section 5.1.2, sources are not expected to begin implementing controls until after the state's SIP has been approved by US EPA. After Nevada's SIP approval, NV Energy would need time for design, permitting, procurement, installation, and startup of either of the two alternative NOx control options for Unit 6 - Piñon Pine #4. Additionally, installation of either of the above control options would require that the combustion turbine be out of service, which requires coordinating for the unit's outage to accommodate regional electrical needs and other regionally affected utilities.

Given these considerations in addition to prioritizing the Valmy conversion and NOx controls that will allow for cessation of coal-fired generation and more immediate emission reductions, it is still reasonably anticipated that compliance with any mandated reduction in NOx emissions for Unit 6 - Piñon Pine #4 would be achieved before the fourth quarter of 2028 (the end of Second Decadal Review period).

5.2.3 Energy and Non-air Quality Impacts of Controls

The DLN conversion would have a negative impact on the plant's water balance and result in a wastewater stream that would require treatment or disposal. Currently, the steam injection system is integrated into the overall plant water balance. Process wastewater is used to produce demineralized water for use in the steam injection system. Elimination of steam injection on the unit would require additional investment in the water treatment system to dispose of the excess wastewater. A DLN conversion will also decrease the electrical generation of the turbine because of the decreased mass flow through the turbine's compressor section. This lost power will need to be made up elsewhere.

Implementation of SCR would result in an increase in the parasitic electrical load of the station. Placement of the SCR catalyst grid in the exhaust flow path of the HRSG would cause backpressure on the turbine which increases the parasitic electrical load of the station. This increased energy use is reflected in the economic analysis as one of the operating costs for SCR. Additionally, there would be some increased energy demand for vaporizing and injecting the ammonia.

Additionally, SCR utilizes some form of ammonia as a reagent to promote the conversion of NOx to N2. Some of the ammonia is unreacted in the process and is emitted out the stack as ammonia "slip". Ammonia emissions are typically between 2 to 10 ppm. Ammonia is a hazardous air pollutant but is not considered harmful at this level. Ammonia for these processes can be provided using either anhydrous ammonia, aqueous ammonia or urea. Storage and use of these forms of ammonia, especially anhydrous ammonia, can have significant safety concerns. However, with proper system design and operation, these safety issues are considered manageable.

5.2.4 Remaining Useful Life of the Facility

As mentioned previously for the purposes of the economic analysis, it has been assumed that this unit will continue to operate at least 30 years after any of the technically feasible control alternatives were to be implemented, recognizing that the unit may be retired sooner than 30 years based on the currently-anticipated 2049 retirement date for the station. The 30-year life of the control device is a typical assumption for these types of controls in this analysis unless the expected life of the source itself is notably shorter.

6. Conclusions

6.1 North Valmy Generating Station

Based on this review of the technical feasibility and costs associated with alternative emission controls, AECOM concludes that no further PM, or SO_2 controls beyond converting the North Valmy Generating Station Units 1 and 2 to natural gas firing are warranted, for the following reasons:

- There are no technically-feasible emission control alternatives available to reduce particulate matter emissions below the emission levels achieved with natural gas firing, and
- There are no technically-feasible alternatives that are available to reduce SO_2 emissions from natural gas firing.

FGR, SNCR and SCR are technically-feasible alternatives for control of NOx emissions from Units 1 and 2. Based on the information available at this stage of the engineering design associated with converting the Station to natural gas firing, the cost impact to install either SNCR or FGR on Units 1 and 2 is estimated to be less than the NDEP's threshold for reasonable further progress of $10,000 per ton. Although it appears that the capital cost to install FGR may be less than the cost to install SNCR, or vice versa, a conclusion as to which of these alternatives meets NDEP's reasonable further progress goals for the least cost cannot be estimated at this time.

Accordingly, the PM and SO_2 emission levels that will be achieved by converting Units 1 and 2 to natural gas firing and the use of either FGR or SNCR in conjunction with natural gas-fired Low NOx Burners is concluded to represent reasonable progress for North Valmy Units 1 and 2.

The projected annual average emissions following conversion of the facility to natural gas firing and installing either FGR or SNCR are summarized in Table 7.

Table 7 – North Valmy Generating Station – Projected Annual Emissions for 2028

	Unit 1	Unit 2
Sulfur Dioxide (ton/yr)	1.48	1.96
Nitrogen Oxides (ton/yr)	258.5	343.3
Particulate Matter (ton/yr)	18.71	24.85

With the conversion of the Station to natural gas firing and the use of Low NOx Burners in conjunction with either FGR or SNCR, the emission rates that correspond to these annual emission rates are 0.1029 lb NOx/MMBtu, 0.0006 lb SO2/MMBtu, and 0.0075 lb PM/MMBtu.

NV Energy intends to convert both Unit 1 and Unit 2 at the North Valmy Generating Station from coal to natural gas firing upon State Implementation Plan approval and issuance of a permit modification. Subject to these approvals, conversion on one unit would commence as soon as late 2025 followed by the second unit in early 2026, allowing for one unit to be operational to meet system reliability needs during the conversion of the units and maintain availability for peak summer run conditions. Delays in permit approvals, supply chain, or similar considerations could potentially extend this time. Understanding these potential constraints, it is still reasonably anticipated that compliance with any mandated reduction in NOx emissions at North Valmy Station would be achieved before the fourth quarter of 2028 (the end of the Second Decadal Review period).

6.2 Tracy Generating Station

Unit 6 (Piñon Pine #4) is a pipeline natural gas-fired combined cycle combustion turbine currently achieving approximately 41 ppm NOx (at 15% O_2) using steam injection. No PM or SO_2 controls beyond the use of clean burning pipeline nature gas is feasible for this unit. Further controls are technically feasible to reduce NOx by use of either SCR or by replacing the current combustor with the latest GE DLN combustor assembly (or both). The estimated cost-effectiveness for conversion of this unit to DLN is over $13,500/ton which is not reasonable. Additionally, the cost of DLN is more expensive than SCR and provides less benefit, so it is clearly not an optimum control option. The estimated cost-effectiveness for implementing SCR is approximately $6,000/ton, which NV Energy understands that NDEP considers reasonable to help achieve reasonable progress toward the goals of the Regional Haze Rule.

The control option to install DLN along with SCR is cost prohibitive because it would only result in a very small incremental reduction in NOx emissions (compared to the use of SCR alone) while the incremental capital and annual costs of installing DLN along with SCR is extremely high (>$18 million capital and over $2 million/yr annual) resulting in an incremental cost-effectiveness for this alternative of over $157,000 per additional ton of emissions reduction.

Based on consideration of the above-described factors, the only reasonable NOx control option for Unit 6 - Piñon Pine #4 is the use of SCR to achieve approximately 4 ppm NOx (at 15% O_2).

It is reasonably anticipated that compliance with any mandated reduction in NOx emissions for Unit 6 - Piñon Pine #4 would be achieved before the fourth quarter of 2028 (the end of the Second Decadal Review period), recognizing that NV Energy is prioritizing the conversion of North Valmy Station to natural gas firing and installing NOx controls that would allow for ceasing coal-fired generation at the Station and more immediate emission reductions.

Appendix A

Potential Emission Control Options –

Capital and Annual Cost Estimates

North Valmy Generating Station

Data Inputs

SNCR Cost Estimate - North Valmy Unit 1

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.00

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 237 MW net

What is the higher heating value (HHV) of the fuel? 1,020 Btu/lb

MWh

What is the estimated actual annual MWh output? 466,437 MWh net

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10.765 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): 8.81 percent by weight

For unit

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	0	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365 days	Plant Elevation	4455 Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.1373 lb/MMBtu		
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.1029 lb/MMBtu		
Estimated Normalized Stoichiometric Ratio (NSR)	0.50		
	50		
Concentration of reagent as stored (C_{stored})	19 Percent		
Density of reagent as stored (ρ_{stored})	58 lb/ft^3		
Concentration of reagent injected (C_{inj})	19 percent		
Number of days reagent is stored ($t_{storage}$)	14 days		
Estimated equipment life	30 Years		
Select the reagent used	Ammonia		

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2024		
CEPCI for 2024	824.5 Enter the CEPCI value for 2024	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index Mar-23
Annual Interest Rate (i)	6.95 Percent		
Fuel ($Cost_{fuel}$)	1.66 $/MMBtu		*must verify
Reagent ($Cost_{reag}$)	0.95 $/gallon for a 19 percent solution of ammonia		*must verify
Water ($Cost_{water}$)	0.0042 $/gallon*		*must verify
Electricity ($Cost_{elect}$)	0.0754 $/kWh		*must verify
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80 $/ton*		*must verify

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	allon of 50% urea	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector M	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	-	Select type of coal	
Fuel Cost ($/MMBtu)	48.80	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Ash Disposal Cost ($/ton)	-	Select type of coal	
Percent sulfur content for Coal (% weight)	-	Select type of coal	
Percent ash content for Coal (% weight)	-	Select type of coal	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	2,554	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	2,078,166	MWh net	
Estimated Actual Annual MWh Output (Boutput) =		466,437	MWh net	
Heat Rate Factor (HRF) =	NPHR/10 =	1.08		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.224	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	1966	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	25	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	87.63	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	86.15	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.18		
Atmospheric pressure at 4455 feet above sea level (P) =	2116x[(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	58 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	65	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	341	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	44.0	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	14,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0802

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	7.7	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.25	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,700,112	in 2024 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2024 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,370,854	in 2024 dollars
Total Capital Investment (TCI) =	$7,892,256	in 2024 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,700,112	in 2024 dollars

Air Pre-Heater Costs (APH_{cost})*
For Coal-Fired Utility Boilers:
$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$
For Coal-Fired Industrial Boilers:
$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2024 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})
For Coal-Fired Utility Boilers:
$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Utility Boilers:
$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$
For Coal-Fired Industrial Boilers:
$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Industrial Boilers:
$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$

Balance of Plant Costs (BOP_{cost}) =	$3,370,854 in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$202,584 in 2024 dollars
Indirect Annual Costs (IDAC) =	$636,510 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$839,094 in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$118,384	in 2024 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$82,253	in 2024 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,134	in 2024 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2024 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$812	in 2024 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2024 dollars
Direct Annual Cost =		$202,584	in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,552	in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$632,959	in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$636,510	in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$839,094	per year in 2024 dollars
NOx Removed =	86.2	tons/year
Cost Effectiveness =	$9,740	per ton of NOx removed in 2024 dollars

Data Inputs

SCR Cost Estimate - North Valmy Unit 1

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.00

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 237 MWh net

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual MWhs output? 466,437 MWhs

Enter the net plant heat input rate (NPHR) 10.765 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 4455 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the *Cost Estimate* tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1373 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0300 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours
Estimated SCR equipment life	30 Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Gas temperature at the SCR inlet (T)	650 ^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

*The SCR inlet temperature of 650 deg.F is a default value. Enter

Concentration of reagent as stored (C_{stored})	19 percent
Density of reagent as stored (ρ_{stored})	58 lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14 days

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024	
CEPCI for 2024	824.5 Enter the CEPCI value for 2024	541.7 2016 CEPCI
Annual Interest Rate (i)	6.95 Percent	
Reagent ($Cost_{reag}$)	0.950 $/gallon for 19% ammonia	*must verify
Electricity ($Cost_{elect}$)	0.0754 $/kWh	*must verify
Catalyst cost ($CC_{replace}$)	254.85 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	
Operator Labor Rate	73.36 $/hour (including benefits)	
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

CEPCI = Chemical Engineering Plant Cost Index   Mar-23

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors fo
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	2,554	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	2,078,166	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		466,437	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.08		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.224	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	1966	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	78.1	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	273.92	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	269.28	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.98		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	1,182,803	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	127.77	/hour	
Residence Time	1/V_{space}	0.47	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.18		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.5	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3112	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF $_{adj}$ x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	9,257.19	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	1,232	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	1,417	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	37.6	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	51	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	58 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	106	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	560	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	72	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	24,300	gallons (storage needed to store a 14 day reagent supply rounded to the nea

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0802

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	1371.31	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$34,568,288	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$755,841	in 2024 dollars
Indirect Annual Costs (IDAC) =	$2,777,664	in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$3,533,505	in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$172,841	in 2024 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$134,977	in 2024 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$203,293	in 2024 dollars
Annual Catalyst Replacement Cost =		$244,729	in 2024 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
	(Q_B/NPHR) x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$755,841	in 2024 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$5,287	in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,772,377	in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,777,664	in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,533,505	per year in 2024 dollars
NOx Removed =	269	tons/year
Cost Effectiveness =	$13,122	per ton of NOx removed in 2024 dollars

Data Inputs

SNCR Cost Estimate - North Valmy Unit 2

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 264 MW

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual MWh output? 575,835 MWh

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 11.584 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	12,000	2.4
Sub-Bituminous	0	0.41	5.84	9,000	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Number of days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.1373	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.1029	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	0.50	

Plant Elevation 4455 Feet above sea level

1.775 NSR

25% Control Efficiency

Concentration of reagent as stored (C_{stored})	19	Percent
Density of reagent as stored (ρ_{stored})	58	lb/ft^3
Concentration of reagent injected (C_{inj})	19	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	30	Years
Select the reagent used	Ammonia	

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2024	
CEPCI for 2024	824.5	Enter the CEPCI value for 2024 541.7 2016 CEPCI
Annual Interest Rate (i)	6.95	Percent
Fuel ($Cost_{fuel}$)	1.66	$/MMBtu
Reagent ($Cost_{reag}$)	0.95	$/gallon for a 19 percent solution of ammonia
Water ($Cost_{water}$)	0.0042	$/gallon*
Electricity ($Cost_{elect}$)	0.0754	$/kWh
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		$/ton

CEPCI = Chemical Engineering Plant Cost Index Mar-23

*need to verify

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Fuel Cost ($/MMBtu)	2.87	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	Not Applicable	Not Applicable	Not Applicable
Percent sulfur content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Percent ash content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate	3.25	Default bank prime rate	Bank prime rate is as of March 2, 2021 and is available as the rates listed under 'bank prime loan' at https://www.federalreserve.gov/releases/h15/.

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	3,058	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	2,312,640	MWh	
Estimated Actual Annual MWh Output (Boutput) =		575,835	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	1.16		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/tplant) =	0.249	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	2181	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	25	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	104.94	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	114.44	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.18		
Atmospheric pressure at 4455 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	12.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	58 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x NSR x MW_R)/(MW_{NOx} x SR) = (whre SR = 1 for NH_3; 2 for Urea)	78	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	409	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	52.7	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	17,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0802

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	8.5	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.30	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour

Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,912,406	in 2024 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2024 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,568,228	in 2024 dollars
Total Capital Investment (TCI) =	$8,424,823	in 2024 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,912,406	in 2024 dollars

Air Pre-Heater Costs (APH_{cost})*
For Coal-Fired Utility Boilers:
$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$
For Coal-Fired Industrial Boilers:
$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2024 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})
For Coal-Fired Utility Boilers:
$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Utility Boilers:
$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$
For Coal-Fired Industrial Boilers:
$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_x Removed/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Industrial Boilers:
$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_x Removed/hr)^{0.12} \times RF$

Balance of Plant Costs (BOP_{cost}) =	$3,568,228 in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$238,120	in 2024 dollars
Indirect Annual Costs (IDAC) =	$679,462	in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$917,582	in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$126,372	in 2024 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$109,268	in 2024 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,400	in 2024 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2024 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$1,079	in 2024 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2024 dollars
Direct Annual Cost =		$238,120	in 2024 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,791	in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$675,671	in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$679,462	in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$917,582	per year in 2024 dollars
NOx Removed =	114	tons/year
Cost Effectiveness =	$8,018	per ton of NOx removed in 2024 dollars

Data Inputs

SCR Cost Estimate - North Valmy Unit 2

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1.00

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 264 MWh net

What is the higher heating value (HHV) of the fuel? 1,020 Btu/scf

What is the estimated actual annual MWhs output? 575,835 MWhs

Enter the net plant heat input rate (NPHR) 11.584 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 4455 Feet above sea level

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the *Cost Estimate* tab. Please select your preferred method:

- Method 1
- Method 2
- Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	365 days	Number of SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	365 days	Number of catalyst layers (R_{layer})	3
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1373 lb/MMBtu	Number of empty catalyst layers (R_{empty})	1
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0300 lb/MMBtu	Ammonia Slip (Slip) provided by vendor	2 ppm
Stoichiometric Ratio Factor (SRF)	1.050	Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)	UNK Cubic feet
		Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK acfm

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000 hours	Gas temperature at the SCR inlet (T)	650 ^{o}F
Estimated SCR equipment life	30 Years*	Base case fuel gas volumetric flow rate factor (Q_{fuel})	484 ft^3/min-MMBtu/hour

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

*The SCR inlet temperature of 650 deg.F is a default value. Enter actual

Concentration of reagent as stored (C_{stored})	19 percent
Density of reagent as stored (ρ_{stored})	56 lb/cubic feet*
Number of days reagent is stored ($t_{storage}$)	14 days

Densities of typical SCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2024	
CEPCI for 2024	824.5 Enter the CEPCI value for 2024 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index — Mar-23
Annual Interest Rate (i)	6.95 Percent	
Reagent ($Cost_{reag}$)	0.950 $/gallon for 19% ammonia	* verification required -Jmin
Electricity ($Cost_{elect}$)	0.0754 $/kWh	* verification required - Jmin
Catalyst cost ($CC_{replace}$)	254.85 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	
Operator Labor Rate	73.36 $/hour (including benefits)	
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Use payroll data, if available, or check current edition of the Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States (https://www.bls.gov/oes/current/oes_nat.htm).
Interest Rate (Percent)	5.5	Default bank prime rate		Use known interest rate or use bank prime rate, available at https://www.federalreserve.gov/releases/h15/.

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	3,058	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	2,312,640	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		575,835	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.16		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.249	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	2181	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	78.1	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	328.01	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	357.72	tons/year	
NO_x removal factor (NRF) =	EF/80 =	0.98		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	1,416,362	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	127.77	/hour	
Residence Time	$1/V_{space}$	0.47	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.18		
Atmospheric pressure at sea level (P) =	2116 x $[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	12.5	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3112	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	11,085.14	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	1,475	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer}$ x $A_{catalyst}))$ + 1 (rounded to next highest integer)	4	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	1,697	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	41.2	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	51	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 56 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	127	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	671	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	90	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	30,200	gallons (storage needed to store a 14 day reagent supply rounded to the near

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0802

Other parameters	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	1574.90	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$37,055,774	in 2024 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$923,055	in 2024 dollars
Indirect Annual Costs (IDAC) =	$2,977,310	in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	$3,900,364	in 2024 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$185,279	in 2024 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$185,712	in 2024 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$259,010	in 2024 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$293,053	in 2024 dollars
Direct Annual Cost =		$923,055	in 2024 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$5,437	in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,971,873	in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,977,310	in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,900,364	per year in 2024 dollars
NOx Removed =	358	tons/year
Cost Effectiveness =	$10,903	per ton of NOx removed in 2024 dollars

Estimated Cost of Flue Gas Recirculation for NOx Control
Valmy Units 1 and 2 - converted to gas firing

Boiler Information

	Unit 1	Unit 2	
Maximum heat input rates, gas firing	2,554	3,058	MMBtu/hr (revised 4FA report SCR and SNCR cost estimates)
Capacity factor, 2016 - 2018 baseline	0.224	0.249	(revised 4FA report SCR and SNCR cost estimates)
Projected future net output	466,437	575,835	net MWhr/yr
NOx emissions rate with LNBs	0.1373	0.1373	lb/MMBtu (AP-42 Table 1.4-1)
	350.53	419.75	lb/hr at full load
	344.60	457.78	ton/yr at projected 2028 capacity factor
Controlled NOx emissions rate	0.1029	0.1029	lb/MMBtu (Estimated 25% reduction)
	258.45	343.33	tons/yr at projected 2028 capacity factor
NOx controlled	86.15	114.44	tons/yr at projected 2028 capacity factor
Exhaust gas temperature	300		°F (estimate)
Flue gas rate at full load	451,613	540,789	wscf/min (basis: F-factor for gas firing, 10,610 wscf/MMBtu)
	650,048	778,409	acfm
Flue gas recirculation rate	162,512	194,602	acfm (basis: estimated at 25% of full load exhaust rate)
Flue gas ductwork pressure drop	5		in. w.c. (estimate)
Flue gas recirculation fan power req't	147	176	HP (EPA Control Cost Manual, Equation 2.10)
Electricity cost	0.0754		$/kWh (see SCR and SNCR cost estimates)
FGR heat rate penalty	0.6%		(estimate)
Projected heat rate with LNBs	10.765	11.584	MMBtu/net MW
Projected heat rate with LNBs & FGR	10.830	11.654	MMBtu/net MW
Fuel penalty with FGR	30,128	40,023	MMBtu/yr
Fuel cost	15.00		$/thousand ft3 (current industrial price, US EIA)
Fuel heating value	1020		Btu/ft3

FGR System Cost Estimate

	Unit 1	Unit 2	
Total installed capital cost	$3,525,000	$3,525,000	(B&W budgetary estimate)
Capital recovery factor, system	0.0802		(basis, 6.95% ROI, 30 year equipment life)
Annualized capital cost	$282,642	$282,642	per year
Recirculation fan power cost	$21,751	$28,895	per year
Additional fuel cost	$443,058	$588,573	per year
O&M costs	$96,938	$96,938	per year (basis: 2.75% of capital cost; EPA-453/R-93-034, pg 6-10)
Total annualized cost:	$844,389	$997,048	per year
Cost effectiveness:	$9,801	$8,712	per ton of NOx controlled

North Valmy Regional Haze Review

Compare Four Factor Analysis NOx Control Cost Estimates - 25 vs 30 yr Equipment Life

	Unit 1						Unit 2					
	SNCR		FGR		SCR		SNCR		FGR		SCR	
Equipment life (years)	30	25	30	25	30	25	30	25	30	25	30	25
Capital Recovery Factor	0.0802	0.0854	0.0802	0.0854	0.0802	0.0854	0.0802	0.0854	0.0802	0.0854	0.0802	0.0854
Inlet emission rate (lb/MMBtu)	0.1373	0.1373	0.1373	0.1373	0.1373	0.1373	0.1373	0.1373	0.1373	0.1373	0.1373	0.1373
Outlet emission rate (lb/MMBtu)	0.1029	0.1029	0.1029	0.1029	0.03	0.03	0.1029	0.1029	0.1029	0.1029	0.03	0.03
% control	25.0%	25.0%	25.0%	25.0%	78.1%	78.1%	25.0%	25.0%	25.0%	25.0%	78.1%	78.1%
Uncontrolled Emissions (tons/yr)	344.60	344.60	344.60	344.60	344.60	344.60	457.78	457.78	457.78	457.78	457.69	457.69
Controlled Emissions (tons/yr)	258.45	258.45	258.45	258.45	75.32	75.32	343.33	343.33	343.33	343.33	99.97	99.97
Reduction (tons/yr)	86.15	86.15	86.15	86.15	269.28	269.28	114.44	114.44	114.44	114.44	357.72	357.72
Installed Capital Cost ($)	$7,892,256	$7,892,256	$3,525,000	$3,525,000	$34,568,288	$34,568,288	$8,424,823	$8,424,823	$3,525,000	$3,525,000	$37,055,774	$37,055,774
Capital Recovery Cost ($/yr)	$632,959	$673,999	$282,642	$301,121	$2,772,377	$2,952,132	$675,671	$719,480	$282,642	$301,121	$2,971,873	$3,164,563
Other O&M Cost ($/yr)	$206,135	$206,135	$561,747	$561,747	$761,128	$761,128	$241,911	$241,911	$714,406	$714,406	$928,491	$928,491
Total Annual Cost ($/yr)	$839,094	$880,134	$844,389	$862,868	$3,533,505	$3,713,260	$917,582	$961,391	$997,048	$1,015,527	$3,900,364	$4,093,054
Cost Effectiveness ($/ton)	$9,740	$10,216	$9,801	$10,016	$13,122	$13,790	$8,018	$8,400	$8,712	$8,874	$10,903	$11,442

Appendix B

Potential Emission Control Options –

Capital and Annual Cost Estimates

Tracy Generating Station

Appendix B - Table B-1
Dry Low NOx Burner Conversion for Pinon Pine #4 (Unit 6)

Capital Costs Associated with DLN Burner Upgrade

Cost Category		*Cost Basis*
Purchased Equipment Cost per GE		
DLN 2.6 Combustion Hardware	$4,166,500	DLN combustor
Gas Fuel Module / Packaging Modif.	$2,964,600	Fuel Module
MK Valve Controls Upgrade	$1,000,000	Control system upgrade to MkVIe
Control Curve Changes	$40,000	Control curve and software modifications
Hazardous Gas Protection	$235,000	Hazardous gas detection probes and protection system
CDM / RDLNT	$225,000	Remote DLN Tuning (RDLNT) and Combustion Dynamics Monitoring (CDM) probes
Combined Cycle Impact Study		GE Estimate included a cost for this study, but its cost is assumed to be covered by below Engineering/Indirect Install. Costs
Purchased Equipment (A)	$8,631,100	
Sales Tax (0.046 * A)	$258,933	4.6% Nevada Sales tax
Freight (0.01 * A)	$86,311	1% of equipment cost assumed vs 5% typical in EPA Cost Manual
Total Purchased Equipment (B)	$8,976,344	Sum of above
Direct Installation costs (0.2 * B)	$1,795,269	Typical Installation 20 - 30% of Equip. Costs per EPA Cost Manual
Indirect Installation Costs (0.2 * B)	$2,692,903	20 - 30% of Equip cost Typical from EPA Cost Manual
- General Facilities		
- Engineering/Home Office		Chemical Engineering Plant Cost Index (CEPCI)
- Process and Project Contingency		Year 2019 607.5
		Year 2024 824.5
Total Capital Investment (2019$)	$13,464,516	In 2019 Dollars as in NVE Original Four Factor Analysis
Total Capital Investment (2024$)	$18,274,063	Escalated to 2024 Dollars per above CEPCI

Notes: Capital Recovery Factor =	0.0802	$= i (1 + i)^n / [(1 + i)^n - 1]$
(n) Equip Life years	30	
(i) Interest Rate	6.95%	
Capital Recovery Annualized ($/yr)	$1,465,300	based on 2023 Dollars (rounded)

Appendix B - Table B-2
Dry Low NOx Burner Conversion for Pinon Pine #4 (Unit 6)

Annual Operating Costs Increase

There are three quantifiable operating cost impacts for DLN converstion 1) Capacity Loss from Derate - which requires purchasing capacity, 2) Heat rate impacts - which requires more fuel use to generate sthe same electrcity, and 3) not using steam which actually saves fuel use. NVE's Resource Planning Department used the PROMOD software model to estimate the changes in operating costs associated with all these factors for a DLN conversion. This software model incorporates numerous variables such as operating unit characteristics, system operating demand, etc. to analyze scenarios for decision making and planning purposes. The PROMOD modeling estimated that the total operating cost impacts would be approximately $680,000/yr for the DLN conversion.

Operating Cost Impact	$680,000	$/yr capacity purchases, heat rate impacts, less steam use.

Other Operating Costs Impacts

Cost of Handling excess Water — Not Quantified (but estimated multiple million dollars capital)

Appendix B - Table B-3
Capital Costs for Selective Catalytic Reduction (SCR) for Pinon Pine #4 (Unit 6)

Capital Costs Associated with SCR (Selective Catalytic Reduction)		
Cost Category		*Cost Basis (itemized below in 2019 dollars, then converted to curent (2023) dollars)*
Equpment Costs		
SCR System Purchase Price (Peerless)	$2,290,900	SCR BUDGETARY PRICE SUMMARY FOR SCR RETROFIT ON 6FA GT/HRSG, Peerless Manufacturing Co (PMC) CECO SCR Technologies, Dallas - 12/23/19
Anxillary Equipment Price (Peerless)	$410,000	Other Anxillary Equpment (e.g. Ammonia tank $350,000 + Hoist/Monorail $60,000) from Peerless quote (not including PLC).
For Control system DCS connection	$300,000	$300,000 for new cabinets and cable trays for DCS system instead of Allen Bradley PLC in Peerless quote (but not added above)
AIG throttling globe valve upgrade	$55,000	11 valves * $5,000 upgrade cost to globe type verses inferior gate or butterfly type in Peerless estimate. Needed per NVE standards.
AIG Lance cleanouts	$20,000	NVE estimate to add flanged blinds to the ends of all lances per NVE standards
Total Equpment Costs	$3,075,900	Sum of above
Sales Tax (0.046 * A)	$141,491	4.6% Nevada Sales tax
Freight (0.05 * A)	$58,250	$19K freight for base equipment from Peerlesss quote for SCR + 5% of other equipment (5% Typical from OAQPS Cost Manual)
Total Purchased Equipment	$3,275,641	Equipment + Tax + Freight
Direct Installation costs		
Installation Cost (Peerless)	$1,850,000	From Peerless SCR Budgetary Price Estimate
Local Labor Rate Adjustment to Install cost	$92,500	Installation cost adjustment for higher labor rates in Reno NV area vs national average (+ 5%) (see attached)
Heat tracing and insulation	$50,000	Peerless estimate doesn't include (it states to be provided by NVE). Cost estimate by NVE
Sampling grid	$150,000	Cost to build scaffold and labor for installing permanent grid for tuning, sampling. Estim. By NVE
Tuning	$100,000	Needed after installation. Assume 4 days testing and valve adjustments. Estimate by NVE
CFD modeling (not in Peerless estimate)	$50,000	Recommended by Peerless, but not in their estimate. Estimated costs by NVE and includes one set of NOx tests. (separate from tuning tests)
A. Total Direct Costs (Equip. & Installation)	$5,568,141	
Indirect Installation Costs		
- General Facilities	$278,407	5% of Total Direct Costs = A * 0.05 (per EPA Cost Manual SCR section)
- Engineering/Home Office	$556,814	10% of Total Direct Costs = A * 0.10 (per EPA Cost Manual SCR section)
- Process Contingency	$278,407	5% of Total Direct Costs = A * 0.05 (per EPA Cost Manual SCR section)
B. Indirect Installation Costs	$1,113,628	sum of above
C. Project Contingency	$1,002,265	15% of Direct and Indirect Costs = (A+B)*0.15
Total Project Capital Expense	$7,684,035	A + B + C
Extra Costs for EPC Contract (15%)	$1,152,605	EPC contractor costs consistent with EPA's Retrofit Cost Analyzer spreadsheet
Total Project Capital Expense (2019 $)	$8,836,640	In 2019 Dollars as in NVE Original Four Factor Analysis
Total Project Capital Expense (204 $)	$11,993,103	Escalated to 2023 Dollars using Chemical Engieering Plant Cost Index (CEPCI) for 2019 of 607.5 and for 2024 of 824.5
Notes: Capital Recovery Factor =	0.0786	$= i (1 + i)^n/[(1 + i)^n - 1]$
(n) Equip Life years	30	
(i) Interest Rate	6.75%	
Capital Recovery Annualized ($/yr)	$942,300	Based on 2024 dollars (rounded)

Note 1: Labor Cost Adj. based on US Bureau of Labor Statistics; Reno NV Pipefitter labor vs National Average at: https://data.bls.gov/oes/#/occGeo/One%20occupation%20for%20multiple%20geographical%20areas

Appendix B - Table B-4
Annual Costs for Selective Catalytic Reduction (SCR) for Pinon Pine #4 (Unit 6)

Annual Operating Costs for SCR		
Capacity Loss from Derate and Power Cost for SCR Pressure Drop		
Power Cost and Turbine Derate	$119,220	See separate attachment outlining Power Costs Table B-5
Catalyst Changeout Cost based on Future worth Factor (FWF)		
SCR Annual Cost	$138,700	See separate attachment Table B-6
Annual Maintenance Costs		
Annual Maintenance Costs 0.005 * TCI	$38,420	From SCR OAQPS Cost Manual and Spreadsheet.
Annual Ammonia Injection Tuning	$40,000	Midpoint of range in EPA Cost Control Manual
Reagent Usage		
NOx Removed	192	tons/yr
NOx Removed	43.8	lbs/hr
Molar ratio Ammonia Use / NOx	1.37	Moles NH3/Mole NOx (assumes 90% NOx is NO uses 1:1, 10% is NO2 uses 2:1 molar ratio, + 10ppm slip)
NO2 MW	46.01	lb/lbmole
NH3 MW	17	lb/lbmole
Ammonia Density (100%)/ft3	56	lbs/ft3
Ammonia Density (100%)/gal	7.486	lbs/gal
Ammonia Usage (100%)	3.0	gal/hr
Ammonia Solution concentration	19%	%
Ammonia use at 19% solution	15.583	gal/hr
19% Ammona Solution Cost	0.61	$/gal
Annual Cost	$83,271	
Total of Above Annual Operating Costs	$419,611	Does not include Capital Recovery

Appendix B - Table B-5
Estimate of Tracy Unit 6 Electricity Cost w/SCR

Power Cost due to SCR pressure drop and Derate

NVE is generation capacity limited in the summers. Therefore, there are two electricity related costs association with the backpressure of SCR. 1) The increased energy necessary to overcome the SCR pressure drop and 2) a slight derate to the capacity of the turbine - which requires capacity purhases during the summer to replace the lost capacity.

Extra Energy cost to overcome SCR pressure drop		
P (kW) = Bmw * 1000 * 0.0056 * (CoalF * HRF)^.43		Equation from EPA Control Cost Manual for SCR Utility Boilers Equation applies to boilers - but good approximation for turbines.
Coal F =	1	Use 1 for natural gas per EPA manual
HRF (heat rate factor)	0.827	annual MMBTU/MW/10 (2016-2020 baseline)(Extended baseline period requested by NDEP)
Bmw	107	Unit Megawatt rating (Nominal Output)
Power demand/loss	552	kW (per above formula)
Electricity Price	0.0361	$/kWh EPA value for Utility fuel cost
Annual Utilization	49.3%	(2016-2020 baseline)
Annual cost	$86,090	$/yr (kW * price * %utilization
Generating Capacity Purchases for the derate from SCR		
Additional Capacity Purchase	$33,130	$/yr estimated by NVE based on having to purchase 552 kW capacity coverage for 3 summer months at $20/kWhr
Total Electricity Cost	$119,220	$/yr, Sum of above

Alternate Estimate Basis	$120,760	NVE Resource Planning Dept. estimate as explained below

NVE Resource Planning Department conducted an analysis of the total costs associated with a derate to this unit. Their analysis resulted in an estimated total cost of $120,760/year of which $87,230/year is related to fuel costs overcome the SCR pressure drop and $33,530 for summertime capacity purchases to make up for loss of capacity (derate) of this generating unit. NVE's estimate of fuel costs is very similar to EPA formula cost using EPA suggeted 0.0361 $/kWh. There is a separate cost of $33,530 which is NVE's cost to purchase capacity - whether it is used or not. NVE is capacity limited in the summer (3 months) and any further loss of capacity availability must be made up by purchasing generation capaicty from other companies. This is the cost to have capacity available - whether it is used or not (if it is used, there are additional charges - but that is not included here.) NVE's average cost for capacity purchases is about $20/kW-month. Turbine derate is 552 kW.

Appendix B - Table B-6
Estimate of SCR Catalyst Annual Costs Tracy Unit 6

NVE estimated the annual price for SCR catalyst using EPA's Cost Control Manual Methodology 1. This method uses the combustion unit's size (MMBtu/hr) and other parameters to calculate a catalyst volume (ft3). Then using a unit price $/ft3 for a catalyst changeout and assuming catalyst changeout frequency consistent with examples in EPA's Cost Manual, it provides an estimate of the annual catalyst costs for SCR catalyst. (Note: For conservatism, the MMBtu/hr is based on the turbine capacity only and excludes duct firing. This turbine is permitted for significant duct firing and adding those MMBtu/hr would increase catalyst volume and costs.)

SCR Catalyst Replacement Cost per EPA Control Cost Manual Method 1

Turbine Design Parameters			
Bmw	MW Rating at Full Load	107	MW (note this is the gas turbine alone, and excludes duct firing)
NPHR	Net Plant Heat Input Rate	8.27	MMBtu/MW (actual 2016 - 2020 average)
	Days of Operation	365	days/yr
NOx_{in}	Inlet NOx	0.1512	lb/MMBtu (actual 2016 - 2020 average)
	% control	90.00	% removal for SCR (assumed)
Sulf	Fuel Sulfur Content	0	weight fraction (negligible for Natural Gas
SCR Assumptions:			
N_{scr}	Number of SCR Reactor Chambers	1	Chambers (EPA default in EPA SCR spreadsheet and CCM)
R_{layer}	Number of Catalyst Layers	3	layers (EPA default)
Slip	Ammonia Slip Design	2	ppm (EPA default)
T	Gas Temp. at SCR Inlet	793	F Based on Unit 6 Actual design information
Other Parameters			
i	Interest Rate	6.95%	
y	Frequency of Cat. Changout	3	Years (assume only replace one layer on this frequency, EPA CCM default)
$CC_{replace}$	Catalyst Unit Cost	365	$/ft3 (includes removal, disposal and install.) This is a conservative estimate based on actual ctalyst costs for NVE at Silverhawk facility in 2018 which totalled $469/ft3 (see Attach. E of NVE letter to NDEP of January 15, 2021)
Calculated values and adjustment factors for estimating Catalyst Volume			
Q_B	Max. Heat Input Rate	884.89	MMBtu/hr (=Bmw * NPHR)
Ef_{adj}		1.2391	= 0.2869 + (1.058 * % removal/100)
$Slip_{adj}$		1.1701	= 1.2835 - (0.0567 * Slip)
NOx_{adj}		0.9009	= 0.8524 + (0.3208 * NOx)
S_{adj}		0.9636	= 0.9636 + (0.455 * Sulf)
T_{adj}		1.1700526	$= (15.16 - (0.03937 * T) + (0.0000274 * (T)^2))$
FWF	Future Worth Factor	0.31120	$=i*(1/((1+i)^y-1))$

Attachment F: Estimate of SCR Catalyst Annual Costs (continued)

SCR Calculated Catalyst Volume (entire reactor) EAP CCM Methodology 1			
Vol_{cat}	Catalyst Volume	3661.90	ft3 (calculated)
		Catalyst Volmue (ft3)	$= 2.81 \times Q_B \times Ef_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times (T_{adj}/N_{scr})$
Calc. Annual Catalyst Costs (assuming only one layer (1/3 of total) catalyst is replaced each Changeout.			
	Annual Catalyst Cost w/365 $/ft3	$138,700	$\$/yr = N_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$
		$1,336,592	(FYI - one time cost to change entire catalyst) $= N_{scr} \times Vol_{cat} \times CC_{replace}$

Note: The above Annual Catalyst Cost is based on a conservative 365 $/ft3 unit price for a catalyst changeout. The below cost is calculated based on $469/ft3, which is the actual Silverhawk SCR Catalyst Replacement Project unit cost in 2018

	Annual Catalyst Cost w/469 $/ft3	$178,157	$\$/yr = N_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$

Appendix B - Table B-7
Dry Low NOx Burner Conversion for Pinon Pine #4 (Unit 6)

Table C-2 Summary of Operating Costs

Operating Costs	DLN Combustor Costs	Cost for SCR w/o DLN	Cost for SCR with DLN
Capacity Derate and Power Cost due to SCR Pressure Drop (1)	$680,000	$119,220	$799,220
Catalyst Changeout Costs (annualized with FWF) (2)		$138,700	$69,350
Annual Maintenance Costs		$38,420	$38,420
Annual Ammonia Grid Tuning		$40,000	$40,000
Reagent Useage (3)		$83,271	$29,145
Total Annual Operating Costs (excluding Capital Recovery)	$680,000	$419,611	$976,135

Notes:
(1) Power costs for DLN include BOTH SCR pressure drop related power costs ($119K) and turbine derate-related power loss due to DLN combustor ($680K)
(2) With DLN and SCR, assume lower inlet NOx allows 50% less frequent changouts
(3) With DLN and SCR, assume 65% less reagent with lower NOx ppm at SCR inlet

Appendix C

NV Energy Cost of Capital / Interest Rate

As a regulated utility, NV Energy's cost of capital is determined differently than for an unregulated entity. NV Energy's actual cost of capital for its operating utilities, Nevada Power Company (NPC) and Sierra Pacific Power Company (SPPC), is set by the Public Utility Commission of Nevada (PUCN). The cost of capital for NV Energy's operating utilities consists of several components and are established triennially in a regulatory proceeding called a General Rate Case (GRC). In the most recent GRC from 2022, the PUCN established SPPC's cost of capital (i.e., its rate of return on capital investments) at 6.95%.

The cost-effectiveness tables in this Four Factor Analysis use this 6.95% interest rate assumption and the following paragraph further explains the basis of this PUCN approved rate. The use of this interest rate is consistent with EPA's guidance in their cost control manual which recommends the use of a "firm-specific nominal interest rate if possible" in preference to a generic bank default interest rate when evaluating the economics of potential pollution control options.

As regulated utilities, NPC (southern territory) and SPPC (northern territory, which includes North Valmy and Tracy) must separately go through a GRC filing and approval process with the PUCN. The proceedings include obtaining approval of the cost of capital (interest rate) allowed to be used in setting the utility's customer rates. Based on SPPC's most recent GRC when this four factor update was prepared, the PUCN-approved weighted average cost of capital is 6.95%. This rate recognizes that SPPC's capital expenditures are partially funded through issuance of debt and partially through equity financing. Accordingly, this rate is determined following PUCN procedures and represents a weighted average of SPPC's debt obligations (e.g., issued bonds) and SPPC's allowed return on equity financing. This rate is used in calculating the allowable increase to customer's rates for SPPC to recover the costs of making prudent capital expenditures. Thus, this firm-specific 'interest rate' is the true cost of capital investments for SPPC and is the appropriate value to use when annualizing the capital expenditures that SPPC would take on in order to install air pollution controls.

The PUCN approval of the 6.95% cost of capital can be found in the modified final PUCN order for Dockets No. 22-06014, No. 22-06015, and No. 22-06016, paragraph 71 (see link: 24156.pdf (state.nv.us))

Appendix C – Air Quality Regulations Incorporated by Reference

NV Energy Valmy and Tracy Generating Stations

Provisions provided in the following Nevada regulation for the Valmy and Tracy Generating Facilities are hereby incorporated and adopted into Nevada's Second Regional Haze SIP by reference.

PROPOSED REGULATION OF THE

STATE ENVIRONMENTAL COMMISSION

LCB File No. R138-24

September 17, 2024

EXPLANATION – Matter in ***italics*** is new; matter in brackets ~~[omitted material]~~ is material to be omitted.

AUTHORITY: §§ 1 and 2, NRS 445B.210.

A REGULATION relating to air pollution; requiring the State Environmental Commission to take certain federal requirements into consideration in establishing emission limits, schedules of compliance and other measures for certain sources in this State that emit or may emit air contaminants; establishing the emission limits, schedules of compliance and continuous monitoring, recordkeeping and reporting requirements for certain sources in this State; setting a deadline for the conversion of certain power-generating units from coal to the permanent use of only pipeline quality natural gas as fuel; adopting by reference certain provisions of federal law relating to continuous emission monitoring; and providing other matters properly relating thereto.

Legislative Counsel's Digest:

Existing law authorizes the State Environmental Commission to adopt regulations to prevent, abate and control air pollution. (NRS 445B.210) The United States Environmental Protection Agency (EPA) has adopted federal regulations requiring each state that is a source of emissions which are reasonably attributable to the impairment of visibility, in the form of regional haze, to adopt a state implementation plan which establishes goals that provide for reasonable progress towards achieving natural visibility conditions. (40 C.F.R. §§ 51.300 et seq.) In establishing a reasonable progress goal, existing federal regulations require a State to consider: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources of air contaminants. (40 C.F.R. § 51.308)

Section 1 of this regulation requires the Commission to take those federal requirements for establishing reasonable progress goals into consideration in establishing emission limits, schedules of compliance and other measures for certain sources in this State that emit or may emit air contaminants. **Section 1** also establishes such emission limits, schedules of compliance and continuous monitoring, recordkeeping and reporting requirements for: (1) power-generating unit number 4 Piñon Pine of NV Energy's Tracy Generating Station; and (2) power-generating unit numbers 1 and 2 of NV Energy's North Valmy Generating Station. **Section 1** requires the power-generating unit numbers 1 and 2 of NV Energy's North Valmy Generating Station to be converted from coal to the permanent use of only pipeline quality natural gas as fuel by not later than June 1, 2027.

For power-generating unit number 4 Piñon Pine of NV Energy's Tracy Generating Station and power-generating unit numbers 1 and 2 of NV Energy's North Valmy Generating Station, **section 1** requires the control measures established by **section 1** to be installed and operating and the emissions limit established by **section 1** to be met by each facility not later than 36 months after approval by the EPA of this State's determination of reasonable progress, in accordance with the requirements of federal regulations, for each facility.

Section 2 of this regulation adopts by reference certain provisions of federal law relating to continuous emission monitoring.

Section 1. Chapter 445B of NAC is hereby amended by adding thereto a new section to read as follows:

1. In establishing the emission limits, schedules of compliance and other measures set forth in this section to make reasonable progress towards achieving natural visibility conditions the Commission will, in accordance with the requirements of 40 C.F.R. § 51.308, take into consideration:

(a) The costs of compliance;

(b) The time necessary for compliance;

(c) The energy and non-air quality environmental impacts of compliance; and

(d) The remaining useful life of the source.

2. The sources listed in this subsection must install, operate and maintain the following control measures which are necessary to make reasonable progress towards achieving natural visibility conditions, in accordance with the requirements of 40 C.F.R. § 51.308, and must not emit or cause to be emitted NO_x in excess of the following limits:

(a) For power-generating unit number 4 Piñon Pine of NV Energy's Tracy Generating Station located in hydrographic area 83:

UNIT (CT + Duct Burner)	***NO_x***	
	Emission Limit ($lb/10^6$ Btu, 30-day rolling average)	***Control Type***
4 Piñon Pine	***0.0151***	***Permanent use of only pipeline quality natural gas as fuel, steam injection and selective catalytic reduction***

(b) For power-generating unit numbers 1 and 2 of NV Energy's North Valmy Generating Station located in hydrographic area 64:

UNIT (Boiler)	***NO_x***	
	Emission Limit ($lb/10^6$ Btu, 30-day rolling average)	***Control Type***
1	***0.1029***	***Permanent use of only pipeline quality natural gas as fuel, Low NO_x burners,***

UNIT (Boiler)	NO_x	
	Emission Limit (lb/10^6 Btu, 30-day rolling average)	***Control Type***
2	***0.1029***	***and one of the following: selective noncatalytic reduction, flue gas recirculation or selective catalytic reduction***

3. Each source subject to subsection 2 shall:

(a) Install, calibrate, maintain and operate a continuous monitoring system and record the output of the system for NO_x emissions in compliance with the requirements of this chapter.

(b) Maintain a contemporaneous log of monitoring and recordkeeping in accordance with the monitoring and recordkeeping requirements of this chapter and 40 C.F.R. Part 75, as adopted by reference in NAC 445B.221. Each record in the log must be:

(1) Entered into the log at the end of the shift, end of the day of operation or end of the final day of operation for the month, as appropriate; and

(2) Identified with the calendar date on which the record was entered.

(c) Annually submit a report, in accordance with the reporting requirements of this chapter and 40 C.F.R. Part 75, as adopted by reference in NAC 445B.221, which must include, without limitation, throughput, productions, fuel consumption, hours of operation and emissions.

(d) Record the occurrence and duration of any:

(1) Start-up, shutdown or malfunction in the operation of the source;

(2) Malfunction of the air pollution control equipment of the source; and

(3) Period during which a continuous monitoring system or monitoring device is inoperative at the source.

4. For each source subject to subsection 2, the established control measures must be installed and operating and the emission limits established for each source must be met by that source not later than 36 months after approval by the United States Environmental Protection Agency Region 9 of Nevada's determination of reasonable progress towards achieving natural visibility conditions, in accordance with the requirements of 40 C.F.R. § 51.308, for that source.

5. Power-generating unit numbers 1 and 2 of NV Energy's North Valmy Generating Station must be converted from coal to the permanent use of only pipeline quality natural gas as fuel. The conversion must be completed by not later than June 1, 2027. An initial performance test and performance evaluation that meets the requirements of this chapter must be conducted for PM_{10} ***emissions not later than 180 days after the date on which the conversion is completed.***

6. If the ownership of any emission unit regulated under this section changes, the new owner must comply with the requirements set forth in this section.

Sec. 2. NAC 445B.221 is hereby amended to read as follows:

445B.221 1. Title 40 C.F.R. §§ 51.100(s), 51.100(nn) and 51.301 and Appendix S of 40 C.F.R. Part 51 are hereby adopted by reference as they existed on July 1, 2021.

2. Title 40 C.F.R. § 51.165 is hereby adopted by reference as it existed on July 1, 2021.

3. Appendices M and W of 40 C.F.R. Part 51 are hereby adopted by reference as they existed on July 1, 2021.

4. Title 40 C.F.R. § 52.21 is hereby adopted by reference as it existed on July 1, 2021.

5. Appendix E of 40 C.F.R. Part 52 is hereby adopted by reference as it existed on July 1, 2021.

6. The following subparts of 40 C.F.R. Part 60 are hereby adopted by reference:

(a) Subpart A, except §§ 60.4, 60.8(b)(2), 60.8(b)(3), 60.8(g) and 60.11(e), as it existed on July 1, 2021.

(b) Section 60.21 of Subpart B, as it existed on July 1, 2021.

(c) Subparts C, Cb, Cc, Cd, Ce, Cf, D, Da, Db, Dc, E, Ea, Eb, Ec, F, G, Ga, H, I, J, Ja, K, Ka, Kb, L, M, N, Na, O, P, Q, R, S, Y, Z, AA, AAa, CC, EE, GG, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, VVa, WW, XX, AAA, BBB, DDD, FFF, GGG, GGGa, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, WWW, AAAA, CCCC, DDDD, EEEE, FFFF, IIII, JJJJ, KKKK and QQQQ as they existed on July 1, 2021;

(d) Subpart XXX as it existed on February 14, 2022; and

(e) Subparts OOOO and OOOOa as they existed on July 1, 2019.

7. Appendices A, B and F of 40 C.F.R. Part 60 are hereby adopted by reference as they existed on July 1, 2021.

8. Subparts A, C, D, E, F, H, I, J, K, L, N, O, P, Q, R, T, V, Y, BB and FF of 40 C.F.R. Part 61 are hereby adopted by reference as they existed on July 1, 2021.

9. Appendix B of 40 C.F.R. Part 61 is hereby adopted by reference as it existed on July 1, 2021.

10. The following subparts of 40 C.F.R. Part 63 are hereby adopted by reference:

(a) Subparts B, C, F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, CC, EE, HH, II, JJ, KK, OO, PP, QQ, RR, SS, TT, UU, VV, WW, XX, CCC, EEE, GGG, HHH, III, JJJ, LLL, MMM, OOO, PPP, QQQ, TTT, UUU, VVV, DDDD, EEEE, FFFF, GGGG, HHHH, JJJJ, MMMM, NNNN, OOOO, PPPP, QQQQ, RRRR, SSSS, TTTT, UUUU, WWWW, XXXX, ZZZZ, AAAAA, BBBBB, CCCCC, DDDDD, EEEEE, FFFFF, GGGGG, HHHHH, JJJJJ, LLLLL, NNNNN, PPPPP, QQQQQ, RRRRR, UUUUU, WWWWW, ZZZZZ, BBBBBB, CCCCCC, DDDDDD, EEEEEE, FFFFFF, GGGGGG, HHHHHH, JJJJJJ, LLLLLL, MMMMMM, NNNNNN, PPPPPP, QQQQQQ, RRRRRR, SSSSSS, TTTTTT, VVVVVV, WWWWWW, XXXXXX, ZZZZZZ, AAAAAAA, BBBBBBB, CCCCCCC, EEEEEEE and HHHHHHH as they existed on July 1, 2021;

(b) Subparts MMMMM and OOOOOO as they existed on November 18, 2021;

(c) Subparts A, YY, IIII, KKKK, VVVV, KKKKK and SSSSS as they existed on November 19, 2021;

(d) Subpart AAAA as it existed on February 14, 2022; and

(e) Subpart YYYY as it existed on March 9, 2022.

11. Appendix A of 40 C.F.R. Part 63 is hereby adopted by reference as it existed on July 1, 2021.

12. Title 40 C.F.R. Part 72 is hereby adopted by reference as it existed on July 1, 2021. If the provisions of 40 C.F.R. Part 72 conflict with or are not included in NAC 445B.001 to 445B.390, inclusive, the provisions of 40 C.F.R. Part 72 apply.

13. ***Title 40 C.F.R. Part 75 is hereby adopted by reference as it existed on June 1, 2024.***

14. Title 40 C.F.R. Part 76 is hereby adopted by reference as it existed on July 1, 2021. If the provisions of 40 C.F.R. Part 76 conflict with or are not included in NAC 445B.001 to 445B.390, inclusive, ***and section 1 of this regulation,*** the provisions of 40 C.F.R. Part 76 apply.

~~[14.]~~ ***15.*** Title 42 of the United States Code, section 7412(b), List of Hazardous Air Pollutants, is hereby adopted by reference as it existed on October 1, 1993.

~~[15.]~~ ***16.*** The *Standard Industrial Classification Manual*, 1987 edition, published by the United States Office of Management and Budget, is hereby adopted by reference. A copy of the manual is available, free of charge, at the Internet address **https://www.osha.gov**.

~~[16.]~~ ***17.*** A copy of the publications which contain the provisions adopted by reference in subsections 1 to ~~[14,]~~ ***15,*** inclusive, may be obtained from the:

(a) Division of State Library, Archives and Public Records of the Department of Administration for 10 cents per page.

(b) Government Publishing Office, free of charge, at the Internet address **http://www.gpo.gov/fdsys/**.

~~[17.]~~ ***18.*** The following standards of ASTM International are hereby adopted by reference:

(a) ASTM D5504-08, "Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence," set forth in Volume 05.06 of the *2008 Annual Book of ASTM Standards*. A copy of ASTM D5504-08 is available from ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428-2959, by telephone at (877) 909-2786 or at the Internet address **http://www.astm.org**, for the price of $64.

(b) ASTM D2234/D2234M-07, "Standard Practice for Collection of a Gross Sample of Coal," set forth in Volume 05.06 of the *2008 Annual Book of ASTM Standards*. A copy of ASTM

D2234/D2234M-07 is available from ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428-2959, by telephone at (877) 909-2786 or at the Internet address **http://www.astm.org**, for the price of $64.

(c) ASTM D2013-07, "Standard Practice for Preparing Coal Samples for Analysis," set forth in Volume 05.06 of the *2008 Annual Book of ASTM Standards*. A copy of ASTM D2013-07 is available from ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428-2959, by telephone at (877) 909-2786 or at the Internet address **http://www.astm.org**, for the price of $72.

(d) ASTM D6784-02(2008), "Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method)," set forth in Volume 11.07 of the *2008 Annual Book of ASTM Standards*. A copy of ASTM D6784-02(2008) is available from ASTM International, 100 Barr Harbor Drive, West Conshohocken, Pennsylvania 19428-2959, by telephone at (877) 909-2786 or at the Internet address **http://www.astm.org**, for the price of $72.

(e) ASTM D2015, "Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter," dated April 10, 2000. A copy of ASTM D2015 is available for purchase at the IHS Markit Standards Store, 15 Inverness Way East, Englewood, Colorado 80112, or at the Internet address **http://global.ihs.com**, for the price of $74.

(f) ASTM D5865, "Standard Test Method for Gross Calorific Value of Coal and Coke," dated October 1, 2013. A copy of ASTM D5865 is available for purchase at the IHS Markit Standards Store, 15 Inverness Way East, Englewood, Colorado 80112, or at the Internet address **http://global.ihs.com**, for the price of $83.

~~[18.]~~ ***19.*** For the purposes of the provisions of 40 C.F.R. Parts 60, 61 and 63, adopted by reference pursuant to this section, the Director may not approve alternate or equivalent test methods or alternative standards or work practices.

~~[19.]~~ ***20.*** Except as otherwise provided in subsections 12 and ~~[13,]~~ ***14,*** the provisions adopted by reference in this section supersede the requirements of NAC 445B.001 to 445B.390, inclusive, ***and section 1 of this regulation,*** for all stationary sources subject to the provisions adopted by reference only if those requirements adopted by reference are more stringent.

~~[20.]~~ ***21.*** For the purposes of this section, "administrator" as used in the provisions of 40 C.F.R. Part 60, except Subpart B § 60.21, and Parts 61 and 63, adopted by reference pursuant to this section, means the Director.

Appendix D – Calculations for Nevada's Reasonable Progress Goals

This workbook outlines the calculations to estimate new RPGs for the 20% most impaired days and 20% clearest days at Class I areas in Nevada accounting for controls under 4 factors analysis (4FA) developed in the 2nd round of Regional HNVe Rule planning

Methodology Description

1) Download 2028 WRAP CAMx PSAT results for Nevada source sectors for sulfate and nitrate light extinction as well as total light extinction at each Nevada Class I area from WRAP's Technical Support System (TSS) tool

2) Modeled Nevada EGU ammonium sulfate (oil and gas ammonium nitrate) light extinction values are scaled by the ratios of (2028 WRAP Nevada EGU (Oil&Gas)source emissions minus reduction due to 4FA controls) divided by 2028 WRAP Nevada EGU (Oil&Gas) source emissions for SO2(Nox)

3) Total light extinction at each Nevada Class I Area from 2028 WRAP CAMx modeling is adjusted to reflect the scaled down contributions from EGU sulfate and Oil&Gas nitrate

4) Total light extinction is converted to Deciviews (dv), and scaled by a factor to reflect average after vs. before dv calc.

Descriptions of the worksheets

Modeled_Extinction_2028

Light extinction by PM species on 20% most impaired days and clearest days (Column C to I) and Rayleigh constant (Column J) at class I areas in NV

Column K: total light extinction from all sources without contribution from sulfate and nitrate at class I areas in NV

Column L: total light extinction from all sources and species (bext = Sum(b_species) + b_Rayleigh) at class I areas in NV

Column M: Calculated visibility degradation in dv (dv=10*ln(bext/10) at class I areas in NV

Column N: Visibility degradation from WRAP TSS tool at class I areas in NV

Column O: visibility degradation correction factor at class I areas in NV

Since the scaling factors are applied to average extinction (average over MIDs or clearest days), whereas we really want average deciviews (average of deciviews computed for each individual MID or clearest day), to account for the difference between dv = average(10*log(bext/10)) and dv = 10*log((average bext)/10, an additional factor is applied, dv_TSS / dv_Calc from bext to get dv corrected for averaging ("dv corr. for avg.")

Scaled_Extinction_NV_MID

Lines 4-11: 4FA scaling factor calculations

Line 8: Scaling factor for EGU sector

Line 11: Scaling factor for O&G sector

Lines 13-24: NV anthropogenic extinction on most impaired days at class I areas

Column C to L : Ammonium sulfate and nitrate light extinction by anthropogenic emission sectors in NV at class I areas

Column M: total ammonium sulfate and nitrate light extinction from anthropogenic sources in NV at class I areas

Column N: total light extinction without extinction from anthropogenic ammonium sulfate and nitrate at class I areas in NV

Column O: Column M + Column N

Lines 27-38: Scaled NV anthropogenic extinction on most impaired days at class I areas

Column C to L : Ammonium sulfate and nitrate light extinction by anthropogenic emission sectors in NV at class I areas

Column G : scaled ammonium sulfate from EGU sector in NV at class I area((G16 :G24)*C$8)

Column I : scaled ammonium nitrate from oil and gas sector in NV at class I area((I16 :I24)*C$8)

Column M: total scaled ammonium sulfate and nitrate light extinction from anthropogenic sources in NV at class I areas

Column N: total scaled light extinction in without NV extinction from anthropogenic ammonium sulfate and nitrate in NV at class I areas

Column O: Column M + Column N

Column P: Calculated scaled visibility degradation at class I area in NV (dv=10*LN(bext/10))
Column Q: scaled visibility degradation with correction for averaging
Column R: 4FA Impact on light extinction
Column S:4FA Impact on visibility degradation

Scaled_Extinction_NV_Clearest

Lines 12-23: light extinction from ammonium sulfate and nitrate on most impaired days at class I areas in NV
- Column C and D: Light extinction from ammonium sulfate and nitrate from all sources in NV
- Column E: Ammonium sulfate light extinction from EGU sector in NV
- Column F: Ammonium nitrate light extinction from oil and gas sector in NV
- Column G: Scaled ammonium sulfate light extinction from EGU sector in NV
- Column H: Scaled ammonium nitrate light extinction from oil and gas sector in NV
- Column I and J: Scaled light extinction from ammonium sulfate and nitrate from all sources in NV

Lines 26-37: light extinction from ammonium sulfate and nitrate on clearest days at class I areas in NV
- Column C and D: Light extinction from ammonium sulfate and nitrate from all sources in NV
- Column I: Scaled light extinction from ammonium sulfate from all sources in NV (used column I/ Column C as a scaling factor)
- Column J : Scaled light extinction from ammonium nitrate from all sources in NV (used column J/ Column D as a scaling factor)

Lines 43-54: Scaled extinction on clearest days at class I areas in NV
- Column C: Scaled total ammonium sulfate at class I areas in NV (see "Scaled_Extinction_NV_Clearest E32-E40 for methodology used for scaling)
- Column D: Scaled total ammonium nitrate at class I areas in NV (see "Scaled_Extinction_NV_Clearest E32-E40 for methodology used for scaling)
- Column E to I: Light extinction by PM species (other than ammonium sulfate and nitrate) at class I areas in NV
- Column J: Rayleigh constant
- Column K: total scaled light extinction at class I areas in NV
- Column L: Calculated scaled visibility degradation at class I area in NV (dv=10*LN(bext/10))
- Column M: Scaled visibility degradation with correction for averaging
- Column N: 4FA Impact on light extinction
- Column O: Impact on visibility degradation

RPG Tables

Lines 5-13
- Column C Baseline visibility degradation at Nevada class I areas on most impaired days taken from WRAP's TSS tool
- Column D Current visibility degradation at Nevada class I areas on most impaired days taken from WRAP's TSS tool
- Column E Projected natural conditions visibility degradation at Nevada class I areas on most impaired days taken from WRAP's TSS tool
- Column F Adjusted projected natural conditions visibility degradation at Nevada class I areas on most impaired days taken from WRAP's TSS tool
- Column G Calculated 2028 Uniform Rate of Progress using URP Glidepath at Nevada class I areas on most impaired days taken from WRAP's TSS tool
- Column H Adjusted calculated 2028 Uniform Rate Progress using URP Glidepath at Nevada class I areas on most impaired days taken from WRAP's TSS tool
- Column I Projected Reasonable Progress Goals at Nevada class I areas on most impaired days taken from WRAP's TSS tool
- Column J Calculated impact of four factor analysis controls at Nevada class I areas on most impaired days taken from "Scaled_Extinction_NV_MID"sheet of this workbool
- Column K Calculated Reasonable Progress Goals after incorporating the four factor analysis controls at Nevada class I areas on most impaired days
- Column M Baseline visibility degradation at Nevada class I areas on clearest days taken from WRAP's TSS tool
- Column N Current visibility degradation at Nevada class I areas on clearest days taken from WRAP's TSS tool

	Column O	Projected natural conditions visibility degradation at Nevada class I areas on clearest days taken from WRAP's TSS tool
	Column P	Adjusted projected natural conditions visibility degradation at Nevada class I areas on clearest days taken from WRAP's TSS tool
	Column Q	Calculated 2028 Uniform Rate of Progress using URP Glidepath at Nevada class I areas on clearest days taken from WRAP's TSS tool
	Column R	Projected Reasonable Progress Goals at Nevada class I areas on clearest days taken from WRAP's TSS tool
	Column S	Calculated impact of four factor analysis controls at Nevada class I areas on clearest days taken from "Scaled_Extinction_NV_Clearest"sheet of this workbook
	Column T	Calculated Reasonable Progress Goals after incorporating the four factor analysis controls at Nevada class I areas on clearest days
Lines 18-26	Column C	Slope of the URP Glidepath at Nevada class I areas on most impaired days taken from WRAP's TSS tool
	Column E	Y Intercept of the URP Glidepath at Nevada class I areas on most impaired days taken from WRAP's TSS tool
	Column F	Calculated 2028 Uniform Rate of Progress at Nevada class I areas on most impaired days
Lines 31-39	Column C	Slope of the adjusted URP Glidepath at Nevada class I areas on most impaired days taken from WRAP's TSS tool
	Column E	Y Intercept of the adjusted URP Glidepath at Nevada class I areas on most impaired days taken from WRAP's TSS tool
	Column F	Calculated adjusted 2028 Uniform Rate of Progress at Nevada class I areas on most impaired days

2028 Pojected Extinction (bext) on 20% most impaired and clearest days default EPA projection method
Nevada Class I areas IMPROVE Monitors
From WRAP TSS. Retrieved March 2022.
CAMx scenario: 2014-2018 Baseline & 2028OTBa2
Column C through I retrieved from WRAP TSS Modeling Express Tool #3
Column T retrieved from WRAP TSS Modeling Express Tool #4
Column J (Rayleigh Constant) = Column_T-Sum(Column_J:Column_I)
Column K (b_other) = Sum(Column_E:Column_J)
Column M (dv) = 10*natural_log(Column_L/10)
Column N (from TSS dv) retrieved from WRAP TSS Modeling Express Tool #4
Column O (dvTSS/dvCalc) = Column_N/Column_M

b_other = b_total less b_SO4 and b_NO3
dvTSS/dvCalc = scale correction for avg.{dv(bext)} / dv(avg.{bext})

20% Most Impaired Days

										calculated from b's			from TSS	dvTSS/dvC	
Site	Year	bSO4	bNO3	bOMC	bEC	bSoil	bCM	bSs	bRay	b_other	b_total	dv	dv	alc	TSS b_total
JARB1	2028	3.63	0.55	3.55	0.62	1.04	2.7	0.04	10	17.9443	22.1243	7.94	7.76397	0.978	22.1243

20% Clearest Days

										calculated from b's			from TSS	dvTSS/dvC	
Site	Year	bSO4	bNO3	bOMC	bEC	bSoil	bCM	bSs	bRay	b_other	b_total		dv	alc	TSS b_total
JARB1	2028	0.81	0.2	0.4	0.09	0.08	0.26	0.05	10	10.8814	11.8914	1.73	1.72446	0.995	11.8914

2028 Projected Extinction (bext) on 20% Most Impaired and 20% Clearest days, Nevada IMPROVE monitors

Scale SO4 and NO3 bext from NV sectors by emissions scaling factor

NV EGU 4 Factor Analysis

	Pollutant	SO2 (tpy)	NOx (tpy)	
4FA Red.	North Valmy	2309	1144	change from 4 factor analysis controls relative to the modeled inventory (see Chapter 6 of SIP)
	Tracy	0	225	
	CAMx	2556	3869	NV modeled 2028OTBa2 EGU emissions (WRAP TSS Emissions Express Tool #4)
	scaling factor	0.096635368	0.6461618	ratio of change to total

NV Non-EGU 4 Factor Analysis

4FA Red.	Apex Plant	0	493	change from 4 factor analysis controls relative to the modeled inventory (see Chapter 6 of SIP)
Increase	Fernley Plant	-206	-1463	increase (negative value) of emissions relative to the modeled inventory (see Chapter 6 of SIP)
	Total Change	-206	-970	
	CAMx	1321	8129	NV modeled 2028 industrial non-EGU point emissions (WRAP TSS Emissions Express Tool #2)
	scaling factor	1.155942468	1.1193259	ratio of change to total

20% Most Impaired Days — **NV Anthropogenic extinction**

		b_SO4					b_NO3							
Site	Year	RemainderAnthro	OilGas	NonEGU	Mobile	EGU	RemainderAnthro	OilGas	NonEGU	Mobile	EGU	b_tot_NV	b_non_NV	b_total
JARB1	2028	0.00282	0.00007	0.00285	0.00039	0.02081	0.00042	0.00006	0.00175	0.00536	0.00337	0.0379	22.0864	22.1243

20% Most Impaired Days — **NV Anthropogenic extinction scaled**

		b_SO4					b_NO3					Calculated from b's				dv corr for	change relative to CAMx 2028		
Site	Year	RemainderAnthro	OilGas	NonEGU scaled	Mobile	EGU scaled	RemainderAnthro	OilGas	NonEGU scaled	Mobile	EGU scaled	b_tot_NV	b_non_NV	b_total	dv	avg.	chg. b_total	change dv	
JARB1	2028	0.00282	0.00007	0.003294436	0.00039	0.002011	0.00042	0.00006	0.00195882	0.00536	0.00217757	0.018562	22.0864	22.104962	7.93217	**7.757662**	-0.0193382	-0.00631	7.76

This worksheet uses the impact of 4FA on light extinction on most impaired days to estimate the 4FA impact on light extinction on clearest days
WRAP source apportionment study did not provide light extinction values by source sectors on clearest days
A new appoach is needed for 4FA impact on visibility degradation on clearest days
Scale available Clearest Day extinction for the total of all sources, according to change in total extinction derived from scaling of individual NV sectors.
Calculate the ratio of total contribution of ammonium sulfate (nitrate) to light extinction at each Class I area in Nevada on most impaired days
after 4FA implementation over total contribution before 4FA implementation
Apply the ratios to the total contribution of ammonium sulfate (nitrate) to light extinction at each Class I area in Nevada on clearest days.
Calculate a new total light extinction at each Class I area on clearest days and the new visibility degradation values in deciviews.
Apply the visibility degradation correction factor

20% Most Impaired Days		All sources bext		Anthropogenic bext				Scaled Antropogenic bext				All sources scaled bext	
				EGU		Non EGU		EGU scaled		Non EGU scaled			
Site	Year	bSO4	bNO3	bSO4	bNO3	bSO4	bNO3	bSO4	bNO3	bSO4	bNO3	bSO4	bNO3
JARB1	2028	3.63	0.55	0.02081	0.00337	0.00285	0.00175	0.002011	0.002178	0.003294	0.0019588	3.611201	0.55020882

20% Clearest Days		All sources bext		All sources scaled bext	
Site	Year	bSO4	bNO3	bSO4	bNO3
JARB1	2028	0.81	0.2	0.8058052	0.2000759

20% Clearest Days		**NV Scaled extinction**		**NV extinction at Class I areas** **Other extinction values**								dv corr for	change relative to CAMx 2028		
Site	Year	bSO4 scaled	bNO3 scaled	bOMC	bEC	bSoil	bCM	bSs	bRay	b_total	dv	avg.	chg. b_tota	change dv	
JARB1	2028	0.80580518	0.20007593	0.4	0.09	0.08	0.26	0.05	10	11.88588111	1.7276614	**1.719839**	-0.00552	-0.004621	1.72

Appendix E – Federal Land Manager Consultation

Appendix E.1 - National Park Service

Appendix E.2 - U. S. Forest Service

Appendix E.3 - U. S. Fish and Wildlife Service

Appendix E.4 - Bureau of Land Management

Appendix E.1 – National Park Service

From:	Peters, Melanie
To:	Nicholas Schlafer; Steven McNeece; Ken McIntyre; Andrew Tucker
Cc:	Shepherd, Don; Miller, Debra C; Stacy, Andrea; Salazer, Holly; King, Kirsten L; Prenni, Anthony J; Mcneel, Pleasant - FS; Giles, Franklin E; Allen, Tim; nguyen.khoi@epa.gov; Withey, Charlotte; mays.rory@epa.gov; bohning.scott@epa.gov
Subject:	NPS Consultation Comments on Nevada"s Draft Regional Haze SIP Revision
Date:	Wednesday, June 5, 2024 1:28:24 PM
Attachments:	NPS-NV_RH-RevisionConsultation-Valmy_06.2024.docx NPS-NV_CalculationWorkbooks2024.zip

Hi Nick,

As we discussed yesterday, the NPS team is ahead of schedule with consultation on Nevada's Draft Regional Haze SIP Revision. Please find our detailed feedback and supporting calculation workbooks attached. We sincerely appreciate the work that you and the rest of NDEP are doing for regional haze. We look forward to future opportunities to collaborate and invite you to reach out if you have questions and/or if additional discussion would be helpful.

Best,

Melanie

--

Melanie V. Peters
NPS, Air Resources Division

Office: 303-969-2315
Cell: 720-644-7632

National Park Service (NPS) detailed feedback for the Nevada Division of Environmental Protection (NDEP) on the draft *Revision to the State Implementation Plan for the Second Planning Period.*

June 5, 2024

Contents

1 Executive Summary

The National Park Service (NPS) appreciates the opportunity to review the *Nevada Regional Haze Revision to the State Implementation Plan for the Second Planning Period*. This SIP revision addresses haze-causing emissions from the Tracy and North Valmy generating stations through four-factor re-analysis and establishment of new reasonable progress requirements in lieu of previously planned shut-downs. On June 4, 2024, staff from the NPS Air Resources Division hosted a regional haze consultation meeting with the Nevada Division of Environmental Protection (NDEP) staff to discuss NPS input on the draft SIP. Representatives from the U.S. Forest Service, U.S. Bureau of Land Management, and Environmental Protection Agency (EPA) Region 9 also attended. This document summarizes and provides additional detail supporting NPS conclusions and recommendations presented at the June 4, 2024, meeting, and serve as our formal regional haze consultation, as required by 42 U.S.C. §7491(d).

Nevada is not home to any NPS-managed Class I areas. However, emissions from sources in the state affect visibility at NPS-managed Class I areas in the surrounding region including Craters of the Moon National Monument & Preserve in Idaho and Yosemite National Park in California. We commend NDEP for working with the NPS and other FLMs throughout the SIP development process, conducting a rigorous review of emission control opportunities, and setting a cost threshold that allows for selection of reasonable emission controls. NDEP's consideration and implementation of emission controls for the Tracy and North Valmy generating stations shows commitment to improving regional haze. The NPS appreciates the steps NDEP is taking to reduce haze-causing pollution and address regional haze in our national parks in this planning period. The following facility specific reviews offer recommendations for strengthening the draft revision.

Tracy Generating Station

The NPS fully supports NDEP's reasonable progress control determination requiring the addition of Selective Catalytic Reduction (SCR) to Tracy Unit 7 (Piñon Pine Unit 4). The required emission limit of 0.0148 lb/106 Btu, 12-month rolling average will reduce an estimated 225 tons of nitrogen oxides (NO_x) per year in a cost-effective manner.

North Valmy Generating Station

The NPS review, detailed in Section 2, finds that SCR is likely cost-effective for North Valmy Units 1 and 2. Because SCR emission controls would reduce significantly more NO_x emissions/year than the Selective Non-Catalytic Reduction (SNCR) NDEP identified as reasonable progress for North Valmy, the NPS recommends addition of SCR to both units.

The cost effectiveness of SCR hinges on the future utilization levels of the emission units. If NDEP determines that SCR is not cost-effective on the basis of limited utilization, the NPS recommends inclusion of a federally-enforceable limit on individual unit utilization to that effect.

2 Detailed Review: Nevada Energy – North Valmy Generating Station

2.1 Plant Characteristics & Background

The North Valmy Generating Station (North Valmy) is a 522-megawatt coal-fired power station located near Valmy, Nevada. This facility is about 300 km northwest of Great Basin National Park. Additionally, the facility is 500 km northwest of Zion National Park and 400 km southwest of Craters of the Moon National Monument, both NPS-managed and federally-mandated Class I areas. The facility's generating assets were jointly owned by Nevada Energy (NVE) and Idaho Power Company (IPC). In 2019, NVE and IPC entered into an agreement that allowed IPC to cease participating in the operation of Unit 1 in 2019 and Unit 2 by the end of 2025.

Unit 1 went online in 1981 and is rated at 254.3 MW[1] with a Babcock & Wilcox Boiler. Unit 1 is equipped with Low NO_x Burner (LNB) Technology to control nitrogen oxides (NO_x). Unit 2 followed in 1985 and is rated at 267 MW[2] with a Foster Wheeler Boiler. Unit 2 is also equipped with LNB.

NVE intends to convert both Units 1 and 2 at North Valmy from coal to natural gas-firing upon issuance of a permit modification. Subject to these approvals, conversion on one unit would occur as soon as late 2025 followed by the second unit in early 2026, allowing for one unit to be operational to meet system reliability needs during the conversion of the units and maintain availability for peak summer run conditions.

2.2 Recent Emissions

EPA's Clean Air Markets Program Database (CAMPD) for 2023 shows North Valmy's NO_x emissions at 1,684 tons which ranks it #107 among the 1,343 facilities in CAMPD. North Valmy's 2023 sulfur dioxide (SO_2) emissions in CAMPD were 2,698 tons and ranking #64. North Valmy's carbon dioxide emissions of 1,338,818 tons rank #74 in the US. North Valmy also ranked #1,195 for EGU mercury emissions with 2.1 lb in 2017.

Table 1. North Valmy Unit 1 & 2 2023 SO_2 and NO_x emissions/ranking vs. the 4,090 EGUs in CAMPD

Unit ID	SO_2 Mass (short tons)	SO_2 Mass Rank	Calculated SO_2 Rate (lbs/mmBtu)	Calculated SO_2 Rate (lbs/mmBtu) Rank	NO_x Mass (short tons)	NO_x Mass Rank	NO_x Rate (lbs/mmBtu)	Calculated NO_x Rate (lbs/mmBtu)	Calculated NO_x Rate (lbs/mmBtu) Rank
1	2,204	90	0.753	8	751	244	0.251	0.257	510
2	494	259	0.141	258	932	190	0.261	0.266	487

[1] EPA 2023 Clean Air Markets Program Database
[2] EPA 2023 Clean Air Markets Program Database

2.3 Evaluation of the Clean Air Act Statutory Factors at North Valmy

Conversion of the North Valmy Units 1 and 2 from coal to natural gas burning will address SO_2 and mercury emissions associated with this facility. The NPS agrees that NDEP considered appropriate NO_x emission reduction opportunities by evaluating the potential application of Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR) to these emission units through reasonable progress four-factor analyses.

NDEP Reasonable Progress Control Determination

Based on the four statutory factors applied to the conversion of North Valmy Generating Station to natural gas firing, NDEP concludes that control measures for the reduction of NO_x are necessary to make reasonable progress. NDEP finds that SNCR, and FGR, are both cost effective and below the $10,000/ton threshold, SNCR being the most cost-effective, therefore SNCR and its associated NO_x limit are necessary to achieve reasonable progress.[3] However, SCR and FGR are acceptable alternatives so long as the 0.11 lb/MMBtu emission limit is being met.[4] NDEP is also requiring the continued use of low-NO_x burners on both Units as necessary to meet reasonable progress. The existing baghouse and air atomized ignitors used to control PM_{10} for both Units and the spray dryer with lime slurry used to control SO_2 for Unit 2 are no longer deemed necessary since the conversion to pipeline quality natural gas will reduce PM_{10} and SO_2 emissions so that these controls are no longer cost-effective.

2.3.1 Cost of Compliance - NO_x

NDEP considers controls above $10,000/ton not cost-effective for the second implementation period of the Regional Haze Rule.

In its Good Neighbor Plan, the EPA determined:

> *For this segment of the oil/gas steam units lacking post-combustion NOX control technology, the EPA estimated a weighted-average representative SCR cost of $7,700 per ton (in 2016$ which is equivalent to $10,700 in 2023$).*

Although implementation of the Good Neighbor Plan in Nevada is currently stayed due to litigation, the EPA has determined that it is technically and economically feasible to install and operate SCR on natural gas-fired utility boilers (such as North Valmy Units 1 and 2) with greater than 100 MW output.

Basis for NVE Cost Analysis

NVE used 2016–2018 data from CAMPD to represent expected future utilization after the complete withdrawal of IPC. The critical values in Table 2 (see below) are the 2016–2018 Average Heat Inputs.

---

[3] NVE's analysis of the cost-effectiveness of SNCR contained a 30-year equipment life, 0.50 normalized stoichiometric ratio, and ash disposal cost which are not consistent with the CCM. In addition, NVE's reagent cost is exceptionally high.

[4] This represents a 19% reduction from the uncontrolled emission rate estimated by AP-42.

Table 2. North Valmy Generating Station, 2016–2018 Heat Input and Emissions Rates

	Heat Input (MMBtu/yr)	Baseline Emission Rates (ton/yr)		
		SO_2	NO_x	PM
North Valmy Unit 1				
2016	4,862,104	1,848	797	22.01
2017	3,254,125	1,232	587	16.27
2018	6,169,957	2,357	1,027	27.76
2016 – 2018 Average	4,772,062	1,812 (0.760 lb/MMBtu)	804 (0.337 lb/MMBtu)	22.01 (0.0092 lb/MMBtu)
North Valmy Unit 2				
2016	5,484,226	431	839	54.84
2017	4,194,914	356	674	20.97
2018	9,298,082	716	1,493	37.16
2016 – 2018 Average	6,325,741	501 (0.158 lb/MMBtu)	1,002 (0.317 lb/MMBtu)	37.67 (0.0119 lb/MMBtu)

NDEP assumed that addition of SNCR could reduce anticipated NO_x emissions by 25% (down to 0.103 lb/mmBtu) and that SCR could achieve a 78% reduction (down to 0.3 lb/mmBtu). NDEP estimated that the cost effectiveness of utilizing either SNCR or FGR on North Valmy Units 1 and 2 is below the NDEP threshold for reasonable further progress of $10,000 per ton of NO_x controlled, while the cost effectiveness of SCR exceeds this threshold.

NPS Cost Analysis

The NPS applied EPA's Control Cost Manual (CCM) workbooks for SNCR and SCR to estimate the cost-effectiveness of NOx controls for North Valmy Units 1 and 2, results are presented below.

Table 3. NPS Estimated NO_x Control Cost Analysis for North Valmy Unit 1 and Unit 2.

North Valmy	**Unit #1**		**Unit #2**	
NO_x Control Technology	**SNCR**	**SCR**	**SNCR**	**SCR**
MW rating at full load capacity[1]	254.30	254.3	267	267
Heat Input (mmBtu)[2]	6,251,186	6,251,186	7,016,429	7,016,429
Estimated actual annual MWh output[2]	622,466	622,466	670,476	670,476
Plant heat rate[3]	10.8	10.8	11.6	11.6
Estimated control equipment life (years)[4]	20	30	20	30
Uncontrolled NO_x Emissions (lb/MMBtu)[5]	0.1355	0.1355	0.1355	0.1355
Controlled NO_x Emissions (lb/MMBtu)[6]	0.1094	0.0272	0.1094	0.0272
NO_x Removal Efficiency (%)[7]	19.3	79.9	19.3	79.9
CEPCI for 2023[8]	797.9	797.9	797.9	797.9
Total Capital Investment	$ 7,732,775	$ 34,998,246	$ 8,048,914	$ 36,124,635
Annual Capital Recovery Costs	$ 726,881	$ 2,806,859	$ 756,598	$ 2,897,196
Indirect Annual Cost	$ 730,361	$ 2,811,204	$ 760,220	$ 2,901,467
Annual Interest Rate (%)[9]	6.95	6.95	6.95	6.95
Reagent Cost ($/gal)[10]	$ 0.349	$ 0.349	$ 0.349	$ 0.349
Catalyst cost ($/ft3)[11]		$ 255		$ 255
Direct Annual Cost	$ 208,402	$ 706,330	$ 227,588	$ 777,963
Total Annual Cost	$ 938,763	$ 3,517,534	$ 987,807	$ 3,679,431
Uncontrolled NO_x (tons/year)	454	454	526	526
NO_x Removed (tons/year)	88	363	102	421
Cost Effectiveness ($/ton)	$ 10,708	$ 9,690	$ 9,721	$ 8,745

[1]EPA CAMPD Facility Attributes
[2]For Unit #1, NPS analysis used the average of the 2021-2023 Gross Load and Heat Input in CAMPD to reflect post-pandemic utilization. For Unit #2, NPS analysis used 2023 Gross Load and Heat Input to reflect expected future utilization. Please see the included "NV Energy data" workbook.
[3]Plant heat rate is from the NVE four-factor analysis.
[4]CCM defaults.
[5]From the NVE four-factor analysis.
[6]For SNCR, from CCM SNCR chapter Figure 1.1c. For SCR, from CAMPD 2023 data for wall-fired boilers firing natural gas—see attachment showing "breakpoint" between 0.027 and 0.049 lb/MMBtu. Please see the included "NV Energy data" workbook.
[7]Calculated by included CCM workbooks
[8]From OAQPS which recommended against using any 2024 CEPCI values yet.
[9]From the NVE four-factor analysis.
[10]2023 USGS NH_3 ammonia price statistics
[11]From 2022 IPM SCR model update

The NPS analysis of application of SCR to these specific natural gas-fired steam units shows that SCR can reduce facility NO_x emissions by almost 800 tons/year at an annual cost of $7.2 million for a cost-effectiveness value under $10,000/ton (for both units).[5] The incremental cost-effectiveness of SCR versus SNCR is also less than $10,000/ton for both units.

Note that the Heat Input values used by NVE to estimate control costs were significantly lower than the values used by NPS as shown in Table 3 above. (Please see Table 3, footnote #2 for the NPS rationale for using alternate Heat Input values.) This is why the NVE estimates resulted in lower amounts of NO_x reductions and higher $/ton.

2.3.2 Time Necessary for Compliance

The NPS estimates that SCR can be installed five years from the effective date of EPA approval of the Nevada regional haze SIP.

2.3.3 Energy and Non-air Quality Impacts

Energy and non-air quality impacts are considered as separate factors and typically contribute to adjustments to the cost of compliance. No unique or unusual energy and non-air quality impacts have been raised by Nevada Energy for North Valmy.

2.3.4 Remaining Useful Life

For the purposes of the economic analysis, it has been assumed that both North Valmy Unit 1 and Unit 2 continue to operate at least 30 years after any of the technically feasible control alternatives were to be implemented.

---

[5] These costs are likely overestimated. According to the IPM Model – Updates to Cost and Performance for APC Technologies, SCR Cost Development Methodology for Oil/Gas-fired Boilers February 2023 Project 13527-002 Eastern Research Group, Inc. Prepared by Sargent & Lundy for EPA.

> *the application of SCR technology to oil/gas-fired boilers is similar to coal-fired applications in that a separate reactor is required. However, there are expected to be significant differences in costs categories due to a few factors. Oil and gas-fired units have relatively low particulate matter and, in most cases, sulfur, therefore, the catalyst requirements are different than coal-fired applications. Smaller pitch catalyst can be used resulting in a lower volume of catalyst being required. In most cases, a single layer of catalyst can be used, resulting in much smaller reactors than coal-fired applications with fewer flue gas mixing devices. Furthermore, this reduces the size of new fans for the additional pressure drop. Finally, because the flue gas in very low in sulfur compounds, all air heater and acid-gas mitigation referenced in the coal-fired SCR system is not applicable. As such, the 2021 coal-fired boilers IPM SCR module was used as input to this module along with S&L in-house information for oil and gas applications to adjust the cost factors.*

2.4 Conclusions & Recommendations

NPS analysis of SCR's potential to reduce NO_x emissions at North Valmy Units 1 and 2 finds costs-effectiveness meets the $10,000/ton threshold set by Nevada. The NPS recommends that NDEP require SCR for reasonable progress on both units.

The NPS cost estimates are lower than those provided by NVE because:

- Cost-effectiveness is highly sensitive to capacity utilization.
    - The NPS analysis used more-recent, post-pandemic higher utilization data to reflect anticipated future utilization after IPC departs.
    - If NDEP determines that SCR is not cost-effective on the basis of limited utilization, the NPS recommends inclusion of a federally-enforceable limit on individual unit utilization to that effect.
- In addition, NPS review:
    - used higher Heat Input values than NVE,
    - assumed that SCR could achieve a slightly lower emission rate based on 2023 CAMPD data,
    - used the 2023 (instead of 2024) CEPCI (as advised by OAQPS), and
    - used the 2023 cost of anhydrous ammonia reagent.

North Valmy	Unit #1		Unit #2				
NOx Control Technology	SNCR	SCR	SNCR	SCR			
MW rating at full load capacity[1]	254.30	254.3	267	267			
Heat Input (mmBtu)[2]	6,251,186	6,251,186	7,016,429	7,016,429			
Estimated actual annual MWh output[2]	622,466	622,466	670,476	670,476			
Plant heat rate[3]	10.8	10.8	11.6	11.6			
Estimated control equipment life (years)[4]	20	30	20	30			
Uncontrolled NO_x Emissions (lb/MMBtu)[5]	0.1355	0.1355	0.1355	0.1355			
Controlled NO_x Emissions (lb/MMBtu)[6]	0.1094	0.0272	0.1094	0.0272			
NO_x Removal Efficiency (%)[7]	19.3	79.9	19.3	79.9			
CEPCI for 2023[8]	797.9	797.9	797.9	797.9			
Total Capital Investment	$ 7,732,775	$ 34,998,246	$ 8,048,914	$ 36,124,635			
Annual Capital Recovery Costs	$ 726,881	$ 2,806,859	$ 756,598	$ 2,897,196			
Indirect Annual Cost	$ 730,361	$ 2,811,204	$ 760,220	$ 2,901,467			
Annual Interest Rate (%)[9]	6.95	6.95	6.95	6.95			
Reagent Cost ($/gal)10	$ 0.349	$ 0.349	$ 0.349	$ 0.349			
Catalyst cost ($/$ft^3$)[11]		$ 255		$ 255			
Direct Annual Cost	$ 208,402	$ 706,330	$ 227,588	$ 777,963	Incrementals		
Total Annual Cost	$ 938,763	$ 3,517,534	$ 987,807	$ 3,679,431	$ 2,578,771	$ 2,691,623	$ 5,270,394
Uncontrolled NO_x (tons/year)	454	454	526	526			
NO_x Removed (tons/year)	88	363	102	421	275	319	595
Cost Effectiveness ($/ton)	$ 10,708	$ 9,690	$ 9,721	$ 8,745	$ 9,365	$ 8,434	$ 8,865

[1]EPA CAMPD Facility Attributes

[2]For Unit #1, NPS analysis used the average of the 2021-2023 Gross Load and Heat Input in CAMPD to reflect post-pandemic utilization. For Unit #2, NPS analysis used 2023 Gross Load and Heat Input to reflect expected future utilization. Please see the included "NV Energy data" workbook.

[3]Plant heat rate is from the NVE four-factor analysis.

[4]CCM defaults.

[5]From the NVE four-factor analysis.

[6]For SNCR, from CCM SNCR chapter Figure 1.1c. For SCR, from CAMPD 2023 data for wall-fired boilers firing natural gas—see attachment showing "breakpoint" between 0.027 and 0.049 lb/MMBtu. Please see the included "NV Energy data" workbook.

[7]Calculated by included CCM workbooks

[8]From OAQPS which recommended against using any 2024 CEPCI values yet.

[9]From the NVE four-factor analysis.

[10] 2023 USGS NH_3 ammonia price statistics

[11]From 2022 IPM SCR model update

State	Facility Name	Facility ID	Unit ID	Year	Program Code	County	Source Category	Latitude	Longitude	Owner/Operator	Unit Type	Primary Fuel Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Commercial Operation Date	Operating Status	Max Hourly HI Rate (mmBtu/hr)	Associated Generators & Nameplate Capacity (MWe)
NV	North Valmy	8224	1	2023	ARP, MATS	Humboldt County	Electric Utility	40.8831	-117.1542	Idaho Power Company (Owner),Sierra Pacific Po	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology (Dry Bottom only)	Baghouse		12/11/1981	Operating	2750	254.3
NV	North Valmy	8224	2	2023	ARP, MATS	Humboldt County	Electric Utility	40.8831	-117.1542	Idaho Power Company (Owner),Sierra Pacific Po	Dry bottom wall-fired boiler	Coal	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		5/21/1985	Operating	3050	267

State	Facility Name	Facility ID	Unit ID	Year	Sum of the Operating Time	Gross Load (MWh)	Gross Load (MWh)	SO2 Mass (short tons)	SO2 Rate (lbs/mmBtu)	Calculated SO2 Rate (lbs/mmBtu)	CO2 Mass (short tons)	CO2 Rate (short tons/mmBtu)	NOx Mass (short tons)	NOx Rate (lbs/mmBtu)	Calculated NOx Rate (lbs/mmBtu)	Heat Input (mmBtu)	Heat Rate (mmBtu/ MWh)	Primary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
NV	North Valmy	8224	1	2019	7,518	1,202,709	160	4,041.0	0.708	0.726	1,167,507	0.105	1,963	0.352	0.353	11,131,824	9.3	Coal	Dry bottom wall-fired		Low NOx B	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2020	3,698	442,284	120	1,458.4	0.683	0.689	443,757	0.105	679	0.319	0.321	4,231,094	9.6	Coal	Dry bottom wall-fired		Low NOx B	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2021	4,797	621,369	130	1,645.8	0.582	0.577	598,297	0.105	938	0.325	0.329	5,704,571	9.2	Coal	Dry bottom wall-fired		Low NOx B	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2022	6,442	709,221	110	2,751.9	0.753	0.765	754,488	0.105	1,028	0.280	0.286	7,193,833	10.1	Coal	Dry bottom wall-fired		Low NOx B	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2023	7,088	536,809	76	2,199.8	0.737	0.751	614,088	0.105	751	0.251	0.257	5,855,154	10.9	Coal	Dry bottom wall-fired		Low NOx B	Baghouse		ARP, MATS
					6,109	622,466										6,251,186								

Conversions for NH3 Reagent Costs (if given NH3 costs in $/ton using USGS source referenced in CCM)**

99.5 % Anhydrous conversion from pure NH3:	
480	$/ton pure NH3
0.24	$/lb pure NH3
9.16	$/ft3 (Anhydrous) density
1.22	$/gal NH3
1.22	$/gal 99.5% NH3 solution

NH3 Densities:

19% Aqueous:	57.3	lb/ft3
29% Aqueous:	56.1	lb/ft3
99.5% Anhydrous:	38.15	lb/ft3
50% Urea:	71	lb/ft3

Conversions:

1 ft3 = 7.48 gallons

29.4% Aqueous conversion from pure NH3:	
480	$/ton pure NH3
0.24	$/lb pure NH3
13.46	$/ft3 (29% Aqueous) density
1.80	$/gal NH3
0.529	$/gal 29% NH3 solution

Pure NH3/Urea Costs:	480	$/ton**	Enter USGS commodity price & yr here.
Commodity Year:	2023		Enter USGS commodity cost year here.
Select NH3/Urea Type:	19% Aqueous		

19% Aqueous conversion from pure NH3:	
480	$/ton pure NH3
0.24	$/lb pure NH3
13.75	$/ft3 (19% Aqueous) density
1.84	$/gal NH3
0.349	$/gal 19% NH3 solution

50% Urea Conversion	
480	$/ton Urea
0.24	$/lb Urea
17.04	$/ft3 Urea
2.28	$/gal Urea
1.139	$/gal 50% Urea Solution

Calculation Checks - See CCM Table 2.2 & Example Problem #1:

266	$/ton NH3
78.1	$/ton 29% aqueous solution
0.039	$/lb
2.19	$/ft3
0.293	$/gal
700	$/ton Urea
349.8	$/ton 50% Urea solution
0.175	$/lb
12.42	$/ft3
1.660	$/gal

***Assumes 2016 Cost Year** - This is the Minerals Commodity Summaries Cost Year Used in EPA Example Problem #1

I used this to double check the math for the conversions from $/ton to $/gal percent solution. EPA CCM default assumption is $0.293/gal for 29% solution and $1.660/gal for urea.

**USGS NH3 commodity price statistics (cited in CCM SCR Chapter): https://www.usgs.gov/centers/nmic/nitrogen-statistics-and-information

99.5 % Anhydrous
29.4% Aqueous
19% Aqueous
50% Urea

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(March 2021)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated April 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2016 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 254.3 MW

CAMPD

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWh output? 622,466 MWh

CAMPD 2021-2023

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10.765 MMBtu/MW

NVE 4FA

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	255	days	254.53	CAMPD 2021-2023
Number of days the boiler operates (t_{plant})	255	days		
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.1355	lb/MMBtu	AP-42	
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.1094	lb/MMBtu	CCM Figure 1.1c	
Estimated Normalized Stoichiometric Ratio (NSR)	1.05			

Plant Elevation	4455	Feet above sea level
		NVE 4FA

Concentration of reagent as stored (C_{stored})	19	Percent
Density of reagent as stored (ρ_{stored})	58	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2023				
CEPCI for 2023	797.9	Enter the CEPCI value for 2023	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	6.95	Percent			NVE 4FA
Fuel ($Cost_{fuel}$)	1.66	\$/MMBtu			NVE 4FA
Reagent ($Cost_{reag}$)	0.349	\$/gallon for a 19 percent solution of ammonia			
Water ($Cost_{water}$)	0.0042	\$/gallon*			NVE 4FA
Electricity ($Cost_{elect}$)	0.0754	\$/kWh			NVE 4FA
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton			

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Fuel Cost ($/MMBtu)	2.87	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	Not Applicable	Not Applicable	Not Applicable
Percent sulfur content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Percent ash content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	2,738	MMBtu/hour	2750 mmBtu/hr
Maximum Annual MWh Output =	Bmw x 8760 =	2,227,668	MWh	
Estimated Actual Annual MWh Output (Boutput) =		622,466	MWh	6,251,186 mmBtu/yr
Heat Rate Factor (HRF) =	NPHR/10 =	1.08		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/tplant) =	0.279	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	2448	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	19	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	71.63	lb/hour	371 lb/hr uncontrolled
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	87.67	tons/year	454 tpy uncontrolled
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =	#VALUE!		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.18		
Atmospheric pressure at 4455 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	12.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 58 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	144	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	759	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	97.9	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	32,900	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i(1+i)^n/(1+i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0940

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	17.0	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) $\times ((C_{stored}/C_{inj}) - 1)$ =	82	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	1.17	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,690,334 in 2023 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2023 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,257,955 in 2023 dollars
Total Capital Investment (TCI) =	$7,732,775 in 2023 dollars

#VALUE!

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,690,334 in 2023 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2023 dollars

#VALUE!

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$3,257,955 in 2023 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$208,402	in 2023 dollars
Indirect Annual Costs (IDAC) =	$730,361	in 2023 dollars
Total annual costs (TAC) = DAC + IDAC	$938,763	in 2023 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$115,992	in 2023 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$83,691	in 2023 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$3,139	in 2023 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$835	in 2023 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$4,746	in 2023 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2023 dollars
Direct Annual Cost =		$208,402	in 2023 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,480	in 2023 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$726,881	in 2023 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$730,361	in 2023 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$938,763	per year in 2023 dollars
NOx Removed =	88	tons/year
Cost Effectiveness =	$10,708	per ton of NOx removed in 2023 dollars

Figure 1.1c SNCR NOx Reduction Efficiency Versus Baseline NOx Levels for Coal-fired Utility Boilers
$y = 22.554x + 16.725$

If x =	0.136	
y =	19.3	%
xout =	0.11	

State	Facility Name	Facility ID	Unit ID	Year	Program Code	County	Source Category	Latitude	Longitude	Owner/Operator	Unit Type	Primary Fuel Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Commercial Operation Date	Operating Status	Max Hourly HI Rate (mmBtu/hr)	Associated Generators & Nameplate Capacity (MWe)
NV	North Valmy	8224	1	2023	ARP, MATS	Humboldt County	Electric Utility	40.8831	-117.1542	Idaho Power Company (Owner),Sierra Pacific Po	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology (Dry Bottom only)	Baghouse		12/11/1981	Operating	2750	254.3
NV	North Valmy	8224	2	2023	ARP, MATS	Humboldt County	Electric Utility	40.8831	-117.1542	Idaho Power Company (Owner),Sierra Pacific Po	Dry bottom wall-fired boiler	Coal	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		5/21/1985	Operating	3050	267

State	Facility Name	Facility ID	Unit ID	Year	Sum of the Operating Time	Gross Load (MWh)	Gross Load (MWh)	SO2 Mass (short tons)	SO2 Rate (lbs/mmBtu)	Calculated SO2 Rate (lbs/mmBtu)	CO2 Mass (short tons)	CO2 Rate (short tons/mmBtu)	NOx Mass (short tons)	NOx Rate (lbs/mmBtu)	Calculated NOx Rate (lbs/mmBtu)	Heat Input (mmBtu)	Heat Rate (mmBtu/ MWh)	Primary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
NV	North Valmy	8224	2	2019	4,200	709,566	169	516.7	0.153	0.156	692,557	0.105	1,024	0.289	0.310	6,603,367	9.3	Coal	Dry botton	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2020	4,341	642,581	148	460.7	0.145	0.149	646,893	0.105	967	0.301	0.314	6,167,956	9.6	Coal	Dry botton	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2021	6,668	1,177,825	177	747.0	0.129	0.131	1,193,194	0.105	1,455	0.251	0.256	11,376,761	9.7	Coal	Dry botton	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2022	6,650	943,747	142	736.2	0.148	0.155	994,714	0.105	1,241	0.249	0.262	9,484,308	10.0	Coal	Dry botton	Dry Lime F	Low NOx B	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2023	5,728	670,476	117	493.8	0.134	0.141	735,881	0.105	932	0.261	0.266	7,016,429	10.5	Coal	Dry botton	Dry Lime F	Low NOx B	Baghouse		ARP, MATS

Conversions for NH3 Reagent Costs (if given NH3 costs in $/ton using USGS source referenced in CCM**)

99.5 % Anhydrous conversion from pure NH3:	
480	$/ton pure NH3
0.24	$/lb pure NH3
9.16	$/ft3 (Anhydrous) density
1.22	$/gal NH3
1.22	$/gal 99.5% NH3 solution

NH3 Densities:

19% Aqueous:	57.3	lb/ft3
29% Aqueous:	56.1	lb/ft3
99.5% Anhydrous:	38.15	lb/ft3
50% Urea:	71	lb/ft3

Conversions:

1 ft3 =	7.48	gallons

29.4% Aqueous conversion from pure NH3:	
480	$/ton pure NH3
0.24	$/lb pure NH3
13.46	$/ft3 (29% Aqueous) density
1.80	$/gal NH3
0.529	$/gal 29% NH3 solution

Pure NH3/Urea Costs:	480	$/ton**	Enter USGS commodity price & yr here.
Commodity Year:	2023		Enter USGS commodity cost year here.
Select NH3/Urea Type:	19% Aqueous		

19% Aqueous conversion from pure NH3:	
480	$/ton pure NH3
0.24	$/lb pure NH3
13.75	$/ft3 (19% Aqueous) density
1.84	$/gal NH3
0.349	$/gal 19% NH3 solution

50% Urea Conversion	
480	$/ton Urea
0.24	$/lb Urea
17.04	$/ft3 Urea
2.28	$/gal Urea
1.139	$/gal 50% Urea Solution

Calculation Checks - See CCM Table 2.2 & Example Problem #1:

266	$/ton NH3
78.1	$/ton 29% aqueous solution
0.039	$/lb
2.19	$/ft3
0.293	$/gal
700	$/ton Urea
349.8	$/ton 50% Urea solution
0.175	$/lb
12.42	$/ft3
1.660	$/gal

***Assumes 2016 Cost Year** - This is the Minerals Commodity Summaries Cost Year Used in EPA Example Problem #1

I used this to double check the math for the conversions from $/ton to $/gal percent solution. EPA CCM default assumption is $0.293/gal for 29% solution and $1.660/gal for urea.

**USGS NH3 commodity price statistics (cited in CCM SCR Chapter): https://www.usgs.gov/centers/nmic/nitrogen-statistics-and-information

99.5 % Anhydrous
29.4% Aqueous
19% Aqueous
50% Urea

Air Pollution Control Cost Estimation Spreadsheet
For Selective Non-Catalytic Reduction (SNCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards
(March 2021)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Non-Catalytic Reduction (SNCR) control device. SNCR is a post-combustion control technology for reducing NOx emissions by injecting an ammonia-base reagent (urea or ammonia) into the furnace at a location where the temperature is in the appropriate range for ammonia radicals to react with NOx to form nitrogen and water.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SNCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SNCR control technology and the cost methodologies, see Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated April 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

The spreadsheet can be used to estimate capital and annualized costs for applying SNCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM version 6). The size and costs of the SNCR are based primarily on four parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, and the reagent consumption. This approach provides study-level estimates (±30%) of SNCR capital and annual costs. Default data in the spreadsheet is taken from the SNCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions, such as the boiler configuration and fuel type. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2016 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SNCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 267 MW

CAMPD

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf

*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWh output? 670,476 MWh

CAMPD 2023

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 11.584 MMBtu/MW

NVE 4FA

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

Ash content (%Ash): percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Blend Composition Table

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	239	days	239	CAMPD 2023
Number of days the boiler operates (t_{plant})	239	days		
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.1355	lb/MMBtu	AP-42	
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.1094	lb/MMBtu	CCM Figure 1.1c	
Estimated Normalized Stoichiometric Ratio (NSR)	1.05			

Plant Elevation	4455	Feet above sea level
	NVE 4FA	

Concentration of reagent as stored (C_{stored})	19	Percent
Density of reagent as stored (ρ_{stored})	58	lb/ft^3
Concentration of reagent injected (C_{inj})	10	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years
Select the reagent used	Ammonia	

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SNCR:

Desired dollar-year	2023		
CEPCI for 2023	797.9	Enter the CEPCI value for 2023 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	6.95	Percent	NVE 4FA
Fuel ($Cost_{fuel}$)	1.66	\$/MMBtu	NVE 4FA
Reagent ($Cost_{reag}$)	0.349	\$/gallon for a 19 percent solution of ammonia	USGS 2023
Water ($Cost_{water}$)	0.0042	\$/gallon*	NVE 4FA
Electricity ($Cost_{elect}$)	0.0754	\$/kWh	NVE 4FA
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/ton	

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Fuel Cost ($/MMBtu)	2.87	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	Not Applicable	Not Applicable	Not Applicable
Percent sulfur content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Percent ash content for Coal (% weight)	Not Applicable	Not Applicable	Not Applicable
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	3,093	MMBtu/hour	3050 mmBtu/hr
Maximum Annual MWh Output =	Bmw x 8760 =	2,338,920	MWh	
Estimated Actual Annual MWh Output (Boutput) =		670,476	MWh	7,016,429 mmBtu/yr
Heat Rate Factor (HRF) =	NPHR/10 =	1.16		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/tplant) =	0.287	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	2511	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	19	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	80.93	lb/hour	419 lb/hr uncontrolled
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	101.61	tons/year	526 tpy uncontrolled
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	#VALUE!		Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.18		
Atmospheric pressure at 4455 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	12.5	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	58 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	163	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	857	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	110.6	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	37,200	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0940

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	17.9	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	92	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	1.32	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	0.0	lb/hour	Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$2,831,849	in 2023 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2023 dollars
Balance of Plant Costs (BOP_{cost}) =	$3,359,623	in 2023 dollars
Total Capital Investment (TCI) =	$8,048,914	in 2023 dollars

#VALUE!

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220{,}000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147{,}000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220{,}000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147{,}000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	$2,831,849	in 2023 dollars

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69{,}000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2023 dollars

#VALUE!

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$3,359,623	in 2023 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$227,588	in 2023 dollars
Indirect Annual Costs (IDAC) =	$760,220	in 2023 dollars
Total annual costs (TAC) = DAC + IDAC	$987,807	in 2023 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	0.015 x TCI =	$120,734	in 2023 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$97,004	in 2023 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$3,381	in 2023 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$968	in 2023 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$5,501	in 2023 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0	in 2023 dollars
Direct Annual Cost =		$227,588	in 2023 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,622	in 2023 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$756,598	in 2023 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$760,220	in 2023 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$987,807	per year in 2023 dollars
NOx Removed =	102	tons/year
Cost Effectiveness =	$9,721	per ton of NOx removed in 2023 dollars

Figure 1.1c SNCR NOx Reduction Efficiency Versus Baseline NOx Levels for Coal-fired Utility Boilers
y = 22.554x + 16.725

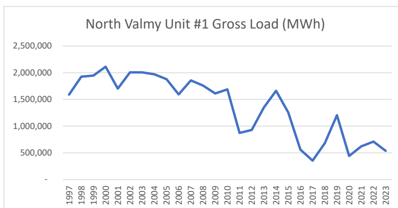
If x =	0.136	
y =	19.3	%
xout =	0.11	

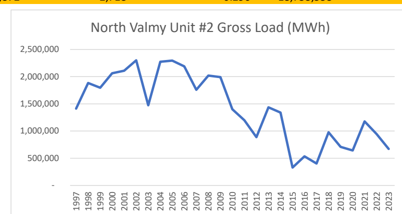
State	Facility Name	Facility ID	Unit ID	Year	Program Code	County	Source Category	Latitude	Longitude	Owner/Operator	Unit Type	Primary Fuel Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Commercial Operation Date	Operating Status	Max Hourly HI Rate (mmBtu/hr)	Associated Generators & Nameplate Capacity (MWe)
NV	North Valmy	8224	1	2023	ARP, MATS	Humboldt County	Electric Utility	40.8831	-117.1542	Idaho Power Company (Owner),Sierra Pacific Pc	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology (Dry Bottom only)	Baghouse		12/11/1981	Operating	2750	254.3
NV	North Valmy	8224	2	2023	ARP, MATS	Humboldt County	Electric Utility	40.8831	-117.1542	Idaho Power Company (Owner),Sierra Pacific Pc	Dry bottom wall-fired boiler	Coal	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		5/21/1985	Operating	3050	267

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Year	Sum of the Operating Time	Gross Load (MWh)	Gross Load (MWh)	SO2 Mass (short tons)	SO2 Rate (lbs/mmBtu)	Calculated SO2 Rate (lbs/mmBtu)	CO2 Mass (short tons)	CO2 Rate (short tons/mmBtu)	NOx Mass (short tons)	NOx Rate (lbs/mmBtu)	Calculated NOx Rate (lbs/mmBtu)	Heat Input (mmBtu)	Heat Rate (mmBtu/MWh)	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
NV	Tracy	2336	3		2019	7,356	303,212	41	1.1	0.001	0.001	208,185	0.059	230	0.134	0.131	3,503,182	11.6	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP
NV	Tracy	2336	3		2020	6,531	278,111	43	1.0	0.001	0.001	191,682	0.059	210	0.131	0.130	3,225,441	11.6	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP
NV	Tracy	2336	3		2021	2,009	98,179	49	0.3	0.001	0.001	67,505	0.059	72	0.126	0.128	1,135,953	11.6	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP
NV	Tracy	2336	3		2022	1,479	55,768	38	0.2	0.001	0.001	40,823	0.059	45	0.123	0.130	686,923	12.3	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP
NV	Tracy	2336	3		2023	841	42,154	50	0.1	0.001	0.001	29,292	0.059	33	0.120	0.132	492,880	11.7	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP
NV	Tracy	2336	4		2019	2,231	116,034	52	0.4	0.001	0.001	86,637	0.059	19	0.036	0.026	1,457,819	12.6	Pipeline Natural Gas	Diesel Oil	Combustion turbine		Dry Low NOx Burners			ARP
NV	Tracy	2336	4		2020	1,957	94,969	49	0.4	0.001	0.001	71,877	0.059	16	0.036	0.027	1,209,468	12.7	Pipeline Natural Gas	Diesel Oil	Combustion turbine		Dry Low NOx Burners			ARP
NV	Tracy	2336	4		2021	1,413	69,721	49	0.3	0.001	0.001	53,072	0.059	15	0.046	0.033	892,944	12.8	Pipeline Natural Gas	Diesel Oil	Combustion turbine		Dry Low NOx Burners			ARP
NV	Tracy	2336	4		2022	2,511	109,942	44	0.4	0.001	0.001	88,019	0.059	22	0.034	0.030	1,481,083	13.5	Pipeline Natural Gas	Diesel Oil	Combustion turbine		Dry Low NOx Burners			ARP
NV	Tracy	2336	4		2023	977	46,012	47	0.2	0.001	0.001	37,137	0.059	10	0.037	0.031	624,902	13.6	Pipeline Natural Gas	Diesel Oil	Combustion turbine		Dry Low NOx Burners			ARP
NV	Tracy	2336	5		2019	1,724	89,363	52	0.3	0.001	0.001	66,953	0.059	19	0.046	0.034	1,126,622	12.6	Pipeline Natural Gas	Diesel Oil	Combustion turbine		Dry Low NOx Burners			ARP
NV	Tracy	2336	5		2020	2,188	106,937	49	0.4	0.001	0.001	82,598	0.059	23	0.042	0.033	1,389,860	13.0	Pipeline Natural Gas	Diesel Oil	Combustion turbine		Dry Low NOx Burners			ARP
NV	Tracy	2336	5		2021	1,602	74,554	47	0.3	0.001	0.001	58,504	0.059	16	0.048	0.032	984,445	13.2	Pipeline Natural Gas	Diesel Oil	Combustion turbine		Dry Low NOx Burners			ARP
NV	Tracy	2336	5		2022	2,381	106,925	45	0.4	0.001	0.001	86,250	0.059	20	0.030	0.028	1,451,355	13.6	Pipeline Natural Gas	Diesel Oil	Combustion turbine		Dry Low NOx Burners			ARP
NV	Tracy	2336	5		2023	1,691	75,876	45	0.3	0.001	0.001	61,878	0.059	14	0.029	0.027	1,041,237	13.7	Pipeline Natural Gas	Diesel Oil	Combustion turbine		Dry Low NOx Burners			ARP
NV	Tracy	2336	6		2019	6,588	509,897	77	1.3	0.001	0.001	248,171	0.059	315	0.151	0.151	4,175,911	8.2	Pipeline Natural Gas		Combined cycle		Other			ARP
NV	Tracy	2336	6		2020	6,415	484,163	75	1.2	0.001	0.001	227,981	0.059	293	0.153	0.153	3,836,178	7.9	Pipeline Natural Gas		Combined cycle		Other			ARP
NV	Tracy	2336	6		2021	5,986	432,974	72	1.1	0.001	0.001	208,910	0.059	268	0.153	0.152	3,515,278	8.1	Pipeline Natural Gas		Combined cycle		Other			ARP
NV	Tracy	2336	6		2022	4,849	335,866	69	0.8	0.001	0.001	163,214	0.059	231	0.168	0.168	2,746,324	8.2	Pipeline Natural Gas		Combined cycle		Other			ARP
NV	Tracy	2336	6		2023	5,658	398,621	70	1.0	0.001	0.001	193,733	0.059	249	0.152	0.153	3,259,931	8.2	Pipeline Natural Gas		Combined cycle		Other			ARP
NV	Tracy	2336	8		2019	8,166	1,665,818	204	3.7	0.001	0.001	730,135	0.059	32	0.005	0.005	12,285,999	7.4	Pipeline Natural Gas		Combined cycle		Dry Low NOx Burners,Selective Catalytic Reduction			ARP
NV	Tracy	2336	8		2020	8,704	1,920,802	221	4.2	0.001	0.001	833,900	0.059	37	0.005	0.005	14,032,008	7.3	Pipeline Natural Gas		Combined cycle		Dry Low NOx Burners,Selective Catalytic Reduction			ARP
NV	Tracy	2336	8		2021	8,360	1,809,660	216	4.0	0.001	0.001	791,022	0.059	35	0.006	0.005	13,310,479	7.4	Pipeline Natural Gas		Combined cycle		Dry Low NOx Burners,Selective Catalytic Reduction			ARP
NV	Tracy	2336	8		2022	7,253	1,446,329	199	3.3	0.001	0.001	657,814	0.059	30	0.007	0.006	11,069,046	7.7	Pipeline Natural Gas		Combined cycle		Dry Low NOx Burners,Selective Catalytic Reduction			ARP
NV	Tracy	2336	8		2023	8,291	1,729,069	209	3.9	0.001	0.001	764,382	0.059	33	0.006	0.005	12,862,204	7.4	Pipeline Natural Gas		Combined cycle		Dry Low NOx Burners,Selective Catalytic Reduction			ARP
NV	Tracy	2336	9		2019	8,136	1,670,988	205	3.7	0.001	0.001	739,867	0.059	32	0.005	0.005	12,449,715	7.5	Pipeline Natural Gas		Combined cycle		Dry Low NOx Burners,Selective Catalytic Reduction			ARP
NV	Tracy	2336	9		2020	8,352	1,859,083	223	4.1	0.001	0.001	812,894	0.059	37	0.006	0.005	13,678,503	7.4	Pipeline Natural Gas		Combined cycle		Dry Low NOx Burners,Selective Catalytic Reduction			ARP
NV	Tracy	2336	9		2021	8,422	1,823,491	217	4.1	0.001	0.001	805,016	0.059	35	0.005	0.005	13,545,928	7.4	Pipeline Natural Gas		Combined cycle		Dry Low NOx Burners,Selective Catalytic Reduction			ARP
NV	Tracy	2336	9		2022	7,314	1,495,373	204	3.4	0.001	0.001	677,032	0.059	29	0.005	0.005	11,392,308	7.6	Pipeline Natural Gas		Combined cycle		Dry Low NOx Burners,Selective Catalytic Reduction			ARP
NV	Tracy	2336	9		2023	8,030	1,699,542	212	3.8	0.001	0.001	752,658	0.059	33	0.006	0.005	12,664,797	7.5	Pipeline Natural Gas		Combined cycle		Dry Low NOx Burners,Selective Catalytic Reduction			ARP

State	Facility Name	Facility ID	Year	Gross Load (MWh)	SO2 Mass (short tons)	CO2 Mass (short tons)	NOx Mass (short tons)	Heat Input (mmBtu)
NV	North Valm	8224	2023	1,207,285	2,694	1,349,968	1,684	12,871,583

State	Facility Name	Facility ID	Unit ID	Year	Sum of the Operating Time	Gross Load (MWh)	Gross Load (MW)	SO2 Mass (short tons)	SO2 Rate (lbs/mm Btu)	Calculated SO2 Rate (lbs/mmBtu)	CO2 Mass (short tons)	CO2 Rate (short tons/mm Btu)	NOx Mass (short tons)	NOx Rate (lbs/mm Btu)	Calculated NOx Rate (lbs/mmBtu)	Heat Input (mmBtu)	Heat Rate (mmBtu/MWh)	Primary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
NV	North Valmy	8224	1	1995			#DIV/0!	3,075		0.603	1,046,790		1,368		0.268	10,204,109	#DIV/0!	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	1996			#DIV/0!	4,686		0.686	1,402,757		2,228		0.326	13,670,923	#DIV/0!	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	1997	8,051	1,589,697	197.459	4,484	0.574	0.597	1,540,579	0.103	2,400	0.303	0.320	15,015,397	9.4	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	1998	8,130	1,924,691	236.754	5,197	0.603	0.602	1,772,776	0.103	3,467	0.387	0.401	17,278,499	9.0	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	1999	8,039	1,947,366	242.24	5,554	0.654	0.657	1,772,096	0.105	3,129	0.361	0.370	16,915,540	8.7	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2000	8,128	2,111,863	259.826	5,673	0.657	0.657	1,790,434	0.104	3,047	0.351	0.353	17,257,367	8.2	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2001	6,843	1,701,468	248.634	4,919	0.665	0.669	1,508,683	0.103	2,527	0.339	0.344	14,704,513	8.6	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2002	8,227	2,007,543	244.034	5,322	0.549	0.547	1,995,231	0.103	2,857	0.293	0.294	19,446,705	9.7	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2003	8,184	2,007,463	245.299	6,021	0.602	0.605	2,042,259	0.103	3,327	0.332	0.334	19,905,097	9.9	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2004	8,160	1,970,572	241.499	7,196	0.729	0.733	2,015,795	0.103	3,538	0.359	0.360	19,647,133	10.0	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2005	7,727	1,878,620	243.14	7,396	0.771	0.779	1,948,344	0.103	3,798	0.396	0.400	18,989,675	10.1	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2006	6,777	1,593,544	235.14	5,352	0.683	0.694	1,582,433	0.103	2,703	0.346	0.351	15,423,316	9.7	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2007	7,926	1,854,536	233.97	5,989	0.676	0.681	1,805,565	0.103	2,990	0.337	0.340	17,598,085	9.5	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2008	7,643	1,760,245	230.318	6,688	0.842	0.850	1,638,712	0.104	2,656	0.333	0.338	15,727,430	8.9	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2009	7,397	1,611,220	217.817	4,923	1.368	0.688	1,501,119	0.105	1,957	0.271	0.274	14,312,758	8.9	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2010	8,254	1,686,811	204.375	5,154	0.679	0.687	1,573,459	0.105	2,568	0.343	0.342	15,002,409	8.9	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2011	5,214	872,484	167.351	2,513	0.635	0.649	812,506	0.105	1,277	0.319	0.330	7,747,031	8.9	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2012	5,754	928,135	161.3	2,893	0.704	0.720	843,207	0.105	1,181	0.288	0.294	8,039,727	8.7	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2013	7,532	1,348,976	179.102	5,123	0.805	0.826	1,300,942	0.105	1,669	0.262	0.269	12,404,118	9.2	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2014	7,740	1,662,293	214.778	6,363	0.816	0.834	1,600,173	0.105	2,243	0.288	0.294	15,257,272	9.2	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	1	2015	7,662	1,256,560	163.994	4,470	0.763	0.774	1,211,930	0.105	1,688	0.293	0.292	11,555,382	9.2	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2016	3,433	557,937	162.517	1,848	0.730	0.755	513,084	0.105	797	0.321	0.326	4,892,104	8.8	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2017	2,327	353,877	152.077	1,232	0.727	0.757	341,292	0.105	587	0.365	0.361	3,254,124	9.2	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2018	3,870	677,681	175.093	2,357	0.742	0.764	647,106	0.105	1,027	0.327	0.333	6,169,957	9.1	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2019	7,518	1,202,709	159.976	4,041	0.708	0.726	1,167,507	0.105	1,963	0.352	0.353	11,131,824	9.3	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2020	3,698	442,284	119.59	1,458	0.683	0.689	443,757	0.105	679	0.319	0.321	4,231,094	9.6	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2021	4,797	621,369	129.543	1,646	0.582	0.577	598,297	0.105	938	0.325	0.329	5,704,571	9.2	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2022	6,442	709,221	110.101	2,752	0.753	0.765	754,488	0.105	1,028	0.280	0.286	7,193,833	10.1	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2023	7,088	536,809	75.7357	2,200	0.737	0.751	614,088	0.105	751	0.251	0.257	5,855,154	10.9	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
				2016-2018 averages	3,210	529,832		1,812			500,494		804			4,772,062	9.0							
				2016-2018 totals	9,630	1,589,495		5,437		0.760	1,501,482		2,411		0.337	14,316,186								
				2021-2023 averages	6,109	622,466		2,199			655,624		906			6,251,186	10.0							
				2021-2023 totals	18,326	1,867,399		6,597		0.704	1,966,872		2,718		0.290	18,753,558								





NV	North Valmy	8224	2	1995			#DIV/0!	725		0.145	1,029,130		1,415		0.282	10,030,033	#DIV/0!	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	1996			#DIV/0!	979		0.148	1,358,256		2,055		0.310	13,238,366	#DIV/0!	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	1997	7,954	1,413,213	177.679	1,203	0.147	0.160	1,545,839	0.103	2,391	0.288	0.318	15,048,455	10.6	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	1998	7,870	1,882,608	239.221	1,192	0.125	0.121	2,036,015	0.103	3,762	0.366	0.381	19,744,956	10.5	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	1999	7,436	1,796,552	241.594	1,275	0.141	0.135	1,957,949	0.104	3,495	0.353	0.371	18,839,839	10.5	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2000	7,667	2,061,930	268.953	1,567	0.153	0.146	2,208,439	0.103	4,142	0.377	0.386	21,476,244	10.4	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2001	7,776	2,108,130	271.107	1,542	0.141	0.141	2,240,139	0.103	4,498	0.404	0.412	21,832,941	10.4	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2002	8,472	2,300,480	271.531	1,552	0.127	0.127	2,513,665	0.103	5,014	0.402	0.409	24,499,702	10.6	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2003	5,425	1,474,015	271.72	1,172	0.154	0.150	1,600,608	0.103	3,608	0.448	0.463	15,600,497	10.6	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2004	8,061	2,272,894	281.962	1,851	0.162	0.162	2,342,831	0.103	5,090	0.440	0.446	22,834,666	10.0	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2005	8,101	2,294,328	283.215	2,211	0.187	0.186	2,440,588	0.103	5,582	0.468	0.469	23,787,405	10.4	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2006	7,894	2,189,478	277.36	1,808	0.163	0.164	2,256,906	0.103	4,812	0.430	0.437	21,997,163	10.0	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2007	6,915	1,757,519	254.147	1,353	0.148	0.147	1,889,485	0.103	3,868	0.408	0.420	18,416,030	10.5	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2008	7,795	2,020,341	259.187	1,446	0.159	0.154	1,956,564	0.104	4,091	0.420	0.436	18,768,654	9.3	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2009	8,152	1,990,759	244.203	1,441	0.152	0.151	2,007,774	0.105	3,733	0.380	0.390	19,143,530	9.6	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2010	6,578	1,399,846	212.8	1,158	0.163	0.166	1,460,420	0.105	2,471	0.337	0.355	13,924,692	9.9	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2011	7,767	1,197,243	154.149	1,036	0.175	0.178	1,221,499	0.105	1,791	0.293	0.308	11,646,645	9.7	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2012	6,235	886,670	142.218	773	0.169	0.183	884,872	0.105	1,278	0.272	0.303	8,436,984	9.5	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2013	7,623	1,437,127	188.526	1,543	0.214	0.220	1,469,230	0.105	2,198	0.301	0.314	14,008,709	9.7	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2014	6,372	1,340,468	210.361	1,454	0.217	0.222	1,376,276	0.105	2,229	0.326	0.340	13,122,425	9.8	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP
NV	North Valmy	8224	2	2015	2,116	328,737	155.381	413	0.314	0.230	376,075	0.105	580	0.294	0.323	3,585,788	10.9	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2016	3,134	535,465	170.845	431	0.153	0.157	575,186	0.105	839	0.291	0.306	5,484,227	10.2	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2017	2,441	403,652	165.358	356	0.161	0.170	439,962	0.105	674	0.297	0.322	4,194,915	10.4	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2018	5,292	977,502	184.706	716	0.148	0.154	975,182	0.105	1,493	0.307	0.321	9,298,082	9.5	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2019	4,200	709,566	168.948	517	0.153	0.156	692,557	0.105	1,024	0.289	0.310	6,603,367	9.3	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2020	4,341	642,581	148.01	461	0.145	0.149	646,893	0.105	967	0.301	0.314	6,167,956	9.6	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2021	6,668	1,177,825	176.636	747	0.129	0.131	1,193,194	0.105	1,455	0.251	0.256	11,376,761	9.7	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2022	6,650	943,747	141.927	736	0.148	0.155	994,714	0.105	1,241	0.249	0.262	9,484,308	10.0	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2023	5,728	670,476	117.044	494	0.134	0.141	735,881	0.105	932	0.261	0.266	7,016,429	10.5	Coal	Dry bottom wall-fired boiler	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
				2016-2018 averages	3,622	638,873	174	501			663,443		1,002			6,325,741	9.9							
				2016-2018 totals	10,867	1,916,618		1,503		0.158	1,990,330		3,006		0.317	18,977,224								

Table 1 – North Valmy Generating Station – 2016-2018 Heat Input and Emissions Rates

	Heat Input (MMBtu/yr)	Baseline Emission Rates (ton/yr)		
		SO_2	**NOx**	**PM**
North Valmy Unit 1				
2016	4,862,104	1,848	797	22.01
2017	3,254,125	1,232	587	16.27
2018	6,169,957	2,357	1,027	27.76
2016 – 2018 Average	**4,772,062**	**1,812 (0.760 lb/MMBtu)**	**804 (0.337 lb/MMBtu)**	**22.01 (0.0092 lb/MMBtu)**
North Valmy Unit 2				
2016	5,484,226	431	839	54.84
2017	4,194,914	356	674	20.97
2018	9,298,082	716	1,493	37.16
2016 – 2018 Average	**6,325,741**	**501 (0.158 lb/MMBtu)**	**1,002 (0.317 lb/MMBtu)**	**37.67 (0.0119 lb/MMBtu)**

Stat e	Facility Name	Facility ID	Unit ID	Associated Stacks	Year	Sum of the Operating Time	Gross Load (MWh)	Gross Load (MW)	NOx Mass (short tons)	NOx Mass Rank	NOx Rate (lbs/mm Btu)	Calculated NOx Rate (lbs/mmBtu)	Calculated NOx Rate (lbs/mmBtu) Rank	Calculated NOx Rate (lbs/MWh)	Calculated NOx Rate (lbs/MWh) Rank	Heat Input (mmBtu)	Heat Input Rank	Heat Rate (mmBtu/ MWh)	Heat Rate (mmBtu/ MWh) Rank	Q Rank	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
CA	AES Alamitos	315	5		2023	759	149,123	196	4	3,108	0.006	0.004	3,846	0.048	3,428	1,658,232	1,763	11.1	1,319	3,059	Pipeline Natural Gas	Residual Oil	Dry bottom wall-fired boiler					ARP
CA	Ormond Beach Power, LLC.	350	2		2023	921	195,783	213	7	2,713	0.007	0.007	3,774	0.075	3,089	2,154,446	1,659	11.0	1,401	2,677	Pipeline Natural Gas		Dry bottom wall-fired boiler		Selective Catalytic Reduction			ARP
CA	Ormond Beach Power, LLC.	350	1		2023	424	72,109	170	4	3,129	0.012	0.008	3,373	0.098	2,898	886,704	2,051	12.3	858	3,113	Pipeline Natural Gas		Dry bottom wall-fired boiler		Selective Catalytic Reduction			ARP
CA	AES Redondo Beach	356	8		2023	652	120,192	184	8	2,691	0.025	0.011	2,793	0.127	2,702	1,410,115	1,841	11.7	1,058	2,672	Pipeline Natural Gas	Residual Oil	Dry bottom wall-fired boiler					ARP
TX	Handley Generating Station	3491	4		2023	2,746	568,934	207	36	1,757	0.015	0.011	3,174	0.127	2,703	6,524,582	1,213	11.5	1,152	1,766	Pipeline Natural Gas		Dry bottom wall-fired boiler		Selective Catalytic Reduction			ARP, CSOSG2
TX	Handley Generating Station	3491	5		2023	2,448	498,644	204	42	1,608	0.020	0.014	2,995	0.168	2,545	6,008,048	1,254	12.0	945	1,636	Pipeline Natural Gas		Dry bottom wall-fired boiler		Selective Catalytic Reduction			ARP, CSOSG2
TX	Handley Generating Station	3491	3		2023	3,291	559,981	170	73	1,014	0.019	0.023	3,004	0.260	2,301	6,204,423	1,242	11.1	1,351	1,059	Pipeline Natural Gas		Dry bottom wall-fired boiler		Combustion Modification/Fuel Reburning,Selective Catalytic Reduction			ARP, CSOSG2
TX	Lewis Creek	3457	1		2023	4,896	861,725	176	112	758	0.026	0.026	2,767	0.259	2,306	8,585,513	1,003	10.0	2,220	780	Pipeline Natural Gas		Dry bottom wall-fired boiler		Selective Catalytic Reduction			ARP, CSOSG2
TX	Lake Hubbard	3452	2		2023	3,178	817,275	257	117	747	0.033	0.027	2,479	0.287	2,232	8,838,556	987	10.8	1,539	769	Pipeline Natural Gas	Diesel Oil	Dry bottom wall-fired boiler		Selective Catalytic Reduction,Low NOx Burner Technology w/ Overfire Air			ARP, CSOSG2
TX	Lewis Creek	3457	2		2023	5,718	971,197	170	136	689	0.026	0.027	2,751	0.280	2,252	10,006,613	881	10.3	1,921	717	Pipeline Natural Gas		Dry bottom wall-fired boiler		Selective Catalytic Reduction			ARP, CSOSG2
NY	Astoria Generating Station	8906	31RH	CP30	2023	3,263	377,630	116	52	1,357	0.043	0.049	2,144	0.277	2,257	2,122,308	1,666	5.6	3,603	1,410	Pipeline Natural Gas	Diesel Oil	Dry bottom wall-fired boiler					ARP, CSNOX, CSOSG3, CSSO2G1, RGGI
NY	Astoria Generating Station	8906	32SH	CP30	2023	3,262	377,599	116	51	1,382	0.045	0.050	2,099	0.271	2,275	2,032,043	1,689	5.4	3,608	1,442	Pipeline Natural Gas	Diesel Oil	Dry bottom wall-fired boiler					ARP, CSNOX, CSOSG3, CSSO2G1, RGGI
TX	Cedar Bayou	3460	CBY2		2023	4,148	1,432,773	345	483	332	0.056	0.066	1,916	0.674	1,547	14,574,261	420	10.2	2,049	403	Pipeline Natural Gas		Dry bottom wall-fired boiler		Selective Catalytic Reduction			ARP, CSOSG2
NY	Arthur Kill	2490	20	CS0002	2023	6,416	869,132	135	301	437	0.061	0.066	1,833	0.693	1,527	9,062,772	973	10.4	1,829	495	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP, CSNOX, CSOSG3, CSSO2G1, RGGI
TX	Cedar Bayou	3460	CBY1		2023	4,064	1,642,668	404	732	250	0.060	0.068	1,859	0.891	1,315	21,551,122	189	13.1	608	345	Pipeline Natural Gas		Dry bottom wall-fired boiler		Selective Catalytic Reduction			ARP, CSOSG2
FL	Manatee	6042	PMT1		2023	133	21,182	159	9	2,586	0.059	0.071	1,865	0.881	1,330	264,787	2,750	12.5	788	2,331	Pipeline Natural Gas	Residual Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Cyclone		ARP
KY	R D Green	6639	G1		2023	1,464	164,754	113	65	1,125	0.071	0.079	1,710	0.794	1,433	1,659,453	1,762	10.1	2,130	1,193	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
LA	Big Cajun 2	6055	2B2		2023	3,508	1,002,918	286	430	362	0.078	0.080	1,639	0.858	1,364	10,705,073	809	10.7	1,650	425	Pipeline Natural Gas		Dry bottom wall-fired boiler		Low NOx Burner Technology w/ Overfire Air,Selective Non-catalytic Reduction,Other			ARP, CSOSG2E
NY	Bowline Generating Station	2625	2		2023	765	243,543	318	135	697	0.086	0.106	1,488	1.105	1,051	2,537,440	1,585	10.4	1,835	706	Pipeline Natural Gas	Residual Oil	Dry bottom wall-fired boiler		Overfire Air			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
FL	Gulf Clean Energy Center	641	6	CS67	2023	5,469	588,976	108	357	403	0.103	0.109	1,233	1.212	961	6,554,554	1,210	11.1	1,311	459	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP
MA	Canal Station	1599	2		2023	259	58,697	227	35	1,773	0.092	0.120	1,382	1.205	970	588,570	2,333	10.0	2,170	1,138	Pipeline Natural Gas	Residual Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology w/ Overfire Air,Overfire Air,Combustion Modificatior	Electrostatic Precipitator		ARP, MATS, RGGI, SIPNOX
FL	Gulf Clean Energy Center	641	7	CS67	2023	5,721	1,359,593	238	922	193	0.121	0.122	1,048	1.356	878	15,063,972	389	11.1	1,350	315	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP
AL	E C Gaston	26	1	CS0CAN	2023	3,865	399,498	103	251	471	0.106	0.124	1,193	1.254	930	4,048,368	1,393	10.1	2,083	517	Pipeline Natural Gas	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G2
OK	Seminole (2956)	2956	3		2023	3,879	900,496	232	603	286	0.103	0.129	1,232	1.340	888	9,375,445	939	10.4	1,841	364	Pipeline Natural Gas		Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Cyclone		ARP, CSOSG2
OK	Seminole (2956)	2956	2		2023	4,259	1,037,218	244	720	255	0.111	0.133	1,147	1.389	863	10,796,815	794	10.4	1,843	347	Pipeline Natural Gas		Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)			ARP, CSOSG2
OK	Seminole (2956)	2956	1		2023	3,533	857,909	243	635	277	0.130	0.137	987	1.480	817	9,275,064	950	10.8	1,547	359	Pipeline Natural Gas		Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)			ARP, CSOSG2
TX	Wilkes Power Plant	3478	3		2023	4,736	601,496	127	411	373	0.107	0.139	1,185	1.367	872	5,898,240	1,257	9.8	2,330	434	Pipeline Natural Gas		Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)			ARP, CSOSG2, TXSO2
AL	E C Gaston	26	3	CS0CBN	2023	2,651	407,612	154	292	444	0.126	0.140	1,008	1.434	843	4,181,195	1,379	10.3	1,973	489	Pipeline Natural Gas	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse,Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G2
MI	Greenwood	6035	1		2023	3,217	970,287	302	693	260	0.116	0.140	1,103	1.428	847	9,877,553	900	10.2	2,040	350	Pipeline Natural Gas	Residual Oil	Dry bottom wall-fired boiler					ARP, CSNOX, CSOSG3, CSSO2G1
TX	Lake Hubbard	3452	1		2023	972	119,377	123	103	785	0.106	0.141	1,194	1.730	706	1,465,920	1,821	12.3	867	810	Pipeline Natural Gas	Diesel Oil	Dry bottom wall-fired boiler		Combustion Modification/Fuel Reburning			ARP, CSOSG2
AL	E C Gaston	26	4	CS0CBN	2023	3,154	412,084	131	291	446	0.130	0.152	980	1.411	856	3,837,838	1,410	9.3	2,583	492	Pipeline Natural Gas	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitator		ARP, CSNOX, CSOSG2, CSSO2G2
AL	Greene County	10	2	CS0EBN	2023	5,227	626,766	120	493	329	0.137	0.161	935	1.572	770	6,117,393	1,248	9.8	2,369	400	Pipeline Natural Gas		Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)			ARP, CSNOX, CSOSG2, CSSO2G2
KY	Big Sandy	1353	BSU1		2023	6,636	1,227,104	185	981	180	0.147	0.167	885	1.599	753	11,735,727	689	9.6	2,481	304	Natural Gas		Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only),Overfire Air	Electrostatic Precipitator		ARP, CSNOX, CSOSG2E, CSSO2G1
TX	Wilkes Power Plant	3478	2		2023	3,823	448,014	117	399	378	0.134	0.170	952	1.783	685	4,699,029	1,344	10.5	1,784	439	Pipeline Natural Gas		Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)			ARP, CSOSG2, TXSO2
LA	Waterford 1 & 2	8056	2		2023	1,341	234,559	175	228	493	0.147	0.174	880	1.943	634	2,613,521	1,570	11.1	1,302	548	Pipeline Natural Gas	Residual Oil	Dry bottom wall-fired boiler		Low NOx Cell Burner,Combustion Modification/Fuel Reburning			ARP, CSOSG2E
FL	Northside	667	3		2023	6,675	1,796,429	269	1,812	91	0.150	0.175	860	2.017	600	20,677,179	214	11.5	1,124	201	Pipeline Natural Gas	Other Gas, Residual Oil	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)			ARP
TX	Sabine	3459	4		2023	5,973	1,937,971	324	1,733	98	0.161	0.180	798	1.788	682	19,279,027	244	9.9	2,232	215	Pipeline Natural Gas		Dry bottom wall-fired boiler		Combustion Modification/Fuel Reburning			ARP, CSOSG2
MS	Watson Electric Generating Plant	2049	4		2023	7,887	1,359,017	172	1,342	137	0.189	0.208	699	1.974	619	12,909,019	570	9.5	2,512	259	Pipeline Natural Gas		Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitator		ARP, CSOSG2
LA	Teche Power Station	1400	3		2023	1,391	181,605	131	205	534	0.184	0.211	710	2.261	558	1,942,013	1,703	10.7	1,641	576	Pipeline Natural Gas	Diesel Oil	Dry bottom wall-fired boiler					ARP, CSOSG2E
LA	Brame Energy Center	6190	1		2023	6,652	1,435,752	216	1,657	106	0.211	0.227	633	2.308	553	14,610,687	417	10.2	2,047	219	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP, CSOSG2E
OK	Riverside (4940)	4940	1501		2023	3,150	614,910	195	888	202	0.226	0.243	586	2.889	466	7,300,295	1,135	11.9	1,009	321	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP, CSOSG2
OK	Riverside (4940)	4940	1502		2023	3,254	556,342	171	822	223	0.224	0.246	591	2.955	458	6,681,789	1,199	12.0	959	331	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP, CSOSG2
AR	Lake Catherine	170	4		2023	784	175,676	224	234	485	0.215	0.252	625	2.665	496	1,860,793	1,725	10.6	1,716	546	Pipeline Natural Gas		Dry bottom wall-fired boiler					ARP, CSOSG2
MS	Watson Electric Generating Plant	2049	5		2023	8,140	2,107,967	259	2,722	36	0.245	0.257	530	2.583	511	21,141,213	200	10.0	2,168	133	Pipeline Natural Gas		Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Electrostatic Precipitator		ARP, CSOSG2
MS	Gerald Andrus	8054	1		2023	799	226,918	284	349	406	0.246	0.263	528	3.076	440	2,652,100	1,559	11.7	1,071	464	Pipeline Natural Gas	Residual Oil	Dry bottom wall-fired boiler		Overfire Air			ARP, CSOSG2
TX	W A Parish	3470	WAP3		2023	2,954	385,961	131	544	310	0.204	0.266	661	2.821	472	4,100,917	1,389	10.6	1,691	384	Pipeline Natural Gas		Dry bottom wall-fired boiler		Overfire Air			ARP, CSOSG2
LA	Little Gypsy	1402	3		2023	2,186	588,350	269	948	185	0.236	0.299	555	3.224	427	6,341,924	1,230	10.8	1,570	311	Pipeline Natural Gas		Dry bottom wall-fired boiler		Combustion Modification/Fuel Reburning			ARP, CSOSG2E
TX	Graham	3490	1		2023	3,098	527,099	170	931	191	0.322	0.379	384	3.532	393	4,912,442	1,329	9.3	2,581	313	Pipeline Natural Gas	Diesel Oil	Dry bottom wall-fired boiler		Combustion Modification/Fuel Reburning			ARP, CSOSG2
TX	Graham	3490	2		2023	2,877	673,662	234	1,425	126	0.299	0.420	422	4.231	350	6,786,701	1,186	10.1	2,128	242	Pipeline Natural Gas	Diesel Oil	Dry bottom wall-fired boiler		Combustion Modification/Fuel Reburning,Overfire Air			ARP, CSOSG2, TXSO2

State	Facility Name	Facility ID	Unit ID	Year	Program Code	County	Source Category	Latitude	Longitude	Owner/Operator	Unit Type	Primary Fuel Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Commercial Operation Date	Operating Status	Max Hourly HI Rate (mmBtu/hr)	Associated Generators & Nameplate Capacity (MWe)
NV	North Valmy	8224	1	2023	ARP, MATS	Humboldt County	Electric Utility	40.8831	-117.1542	Idaho Power Company (Owner),Sierra Pacific Pc	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology (Dry Bottom only)	Baghouse		12/11/1981	Operating	2750	254.3
NV	North Valmy	8224	2	2023	ARP, MATS	Humboldt County	Electric Utility	40.8831	-117.1542	Idaho Power Company (Owner),Sierra Pacific Pc	Dry bottom wall-fired boiler	Coal	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		5/21/1985	Operating	3050	267

0.1355

State	Facility Name	Facility ID	Unit ID	Year	Sum of the Operating Time	Gross Load (MWh)	Gross Load (MWh)	SO2 Mass (short tons)	SO2 Rate (lbs/mmBtu)	Calculated SO2 Rate (lbs/mmBtu)	CO2 Mass (short tons)	CO2 Rate (short tons/mmBtu)	NOx Mass (short tons)	NOx Rate (lbs/mmBtu)	Calculated NOx Rate (lbs/mmBtu)	Heat Input (mmBtu)	Heat Rate (mmBtu/ MWh)	Primary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
NV	North Valmy	8224	1	2019	7,518	1,202,709	160	4,041.0	0.708	0.726	1,167,507	0.105	1,963	0.352	0.353	11,131,824	9.3	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2020	3,698	442,284	120	1,458.4	0.683	0.689	443,757	0.105	679	0.319	0.321	4,231,094	9.6	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2021	4,797	621,369	130	1,645.8	0.582	0.577	598,297	0.105	938	0.325	0.329	5,704,571	9.2	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2022	6,442	709,221	110	2,751.9	0.753	0.765	754,488	0.105	1,028	0.280	0.286	7,193,833	10.1	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
NV	North Valmy	8224	1	2023	7,088	536,809	76	2,199.8	0.737	0.751	614,088	0.105	751	0.251	0.257	5,855,154	10.9	Coal	Dry bottom wall-fired boiler		Low NOx Burner Technology (Dry Bottom only)	Baghouse		ARP, MATS
				2021 - 2023 averages	6,109	622,466										6,251,186	10.0							

Conversions for NH3 Reagent Costs (if given NH3 costs in $/ton using USGS source referenced in CCM**)

99.5 % Anhydrous conversion from pure NH3:	
480	$/ton pure NH3
0.24	$/lb pure NH3
9.16	$/ft3 (Anhydrous) density
1.22	$/gal NH3
1.22	$/gal 99.5% NH3 solution

29.4% Aqueous conversion from pure NH3:	
480	$/ton pure NH3
0.24	$/lb pure NH3
13.46	$/ft3 (29% Aqueous) density
1.80	$/gal NH3
0.529	$/gal 29% NH3 solution

19% Aqueous conversion from pure NH3:	
480	$/ton pure NH3
0.24	$/lb pure NH3
13.75	$/ft3 (19% Aqueous) density
1.84	$/gal NH3
0.349	$/gal 19% NH3 solution

50% Urea Conversion	
480	$/ton Urea
0.24	$/lb Urea
17.04	$/ft3 Urea
2.28	$/gal Urea
1.139	$/gal 50% Urea Solution

NH3 Densities:

19% Aqueous:	57.3	lb/ft3
29% Aqueous:	56.1	lb/ft3
99.5% Anhydrous:	38.15	lb/ft3
50% Urea:	71	lb/ft3

Conversions:

1 ft3 = 7.48 gallons

Pure NH3/Urea Costs:	480	$/ton**
Commodity Year:	2023	
Select NH3/Urea Type:	19% Aqueous	

Enter USGS commodity price & yr here.
Enter USGS commodity cost year here.

Calculation Checks - See CCM Table 2.2 & Example Problem #1:

266	$/ton NH3
78.1	$/ton 29% aqueous solution
0.039	$/lb
2.19	$/ft3
0.293	$/gal
700	$/ton Urea
349.8	$/ton 50% Urea solution
0.175	$/lb
12.42	$/ft3
1.660	$/gal

***Assumes 2016 Cost Year** - This is the Minerals Commodity Summaries Cost Year Used in EPA Example Problem #1

I used this to double check the math for the conversions from $/ton to $/gal percent solution. EPA CCM default assumption is $0.293/gal for 29% solution and $1.660/gal for urea.

**USGS NH3 commodity price statistics (cited in CCM SCR Chapter): https://www.usgs.gov/centers/nmic/nitrogen-statistics-and-information

99.5 % Anhydrous
29.4% Aqueous
19% Aqueous
50% Urea

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards

(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 254.3 MW
CAMPD

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf
*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWhs output? 622,466 MWhs
CAMPD 2021-2023

Enter the net plant heat input rate (NPHR) 10.765 MMBtu/MW
NVE 4FA

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 4455 Feet above sea level
NVE 4FA

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ( ) Method 1
- ( ) Method 2
- (•) Not applicable

Enter the following design parameters for the proposed SCR:

Parameter	Value	Units	Source		Parameter	Value	Units
Number of days the SCR operates (t_{SCR})	255	days	254.53	CAMPD 2021-2023	Number of SCR reactor chambers (n_{scr})	1	
Number of days the boiler operates (t_{plant})	255	days			Number of catalyst layers (R_{layer})	3	
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1355	lb/MMBtu	AP-42		Number of empty catalyst layers (R_{empty})	1	
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0272	lb/MMBtu	CAMPD 2023		Ammonia Slip (Slip) provided by vendor	2	ppm
Stoichiometric Ratio Factor (SRF)	1.050				Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)		Cubic feet
					Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)		acfm

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Parameter	Value	Units		Parameter	Value	Units
Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours		Gas temperature at the SCR inlet (T)	650	^{o}F
Estimated SCR equipment life	30	Years*		Base case fuel gas volumetric flow rate factor (Q_{fuel})		ft^3/min-MMBtu/hour

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Parameter	Value	Units
Concentration of reagent as stored (C_{stored})	19	percent
Density of reagent as stored (ρ_{stored})	58	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Parameter	Value	Units	Source
Desired dollar-year	2023		
CEPCI for 2023	797.9	Enter the CEPCI value for 2023 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	6.95	Percent	NVE 4FA
Reagent ($Cost_{reag}$)	0.349	\$/gallon for 19% ammonia	USGS 2023
Electricity ($Cost_{elect}$)	0.0754	\$/kWh	NVE 4FA
Catalyst cost ($CC_{replace}$)	254.85	\$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	NVE 4FA
Operator Labor Rate	73.36	\$/hour (including benefits)	NVE 4FA
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	2,738	MMBtu/hour	2750 mmBtu/hr
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	2,227,668	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		622,466	MWhs	6,251,186 mmBtu/yr
Heat Rate Factor (HRF) =	NPHR/10 =	1.08		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.279	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	2448	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	79.9	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	296.61	lb/hour	371 lb/hr uncontrolled
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	363.02	tons/year	454.1 tpy uncontrolled
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	$1/V_{space}$	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.18		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.5	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.2254	Fraction

Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	10,086.66	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	#VALUE!	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	#VALUE!	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	58 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	115	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	607	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	78	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	26,300	gallons (storage needed to store a 14 day reagent supply rounded to th

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0802

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	1469.94	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86,380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62,680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7,850 \times (2,200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10,530 \times (1,640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5,700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7,640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$34,998,246	in 2023 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$706,330	in 2023 dollars
Indirect Annual Costs (IDAC) =	$2,811,204	in 2023 dollars
Total annual costs (TAC) = DAC + IDAC	$3,517,534	in 2023 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$174,991	in 2023 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$66,908	in 2023 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$271,295	in 2023 dollars
Annual Catalyst Replacement Cost =		$193,137	in 2023 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$706,330	in 2023 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,345	in 2023 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,806,859	in 2023 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,811,204	in 2023 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,517,534	per year in 2023 dollars
NOx Removed =	363	tons/year
Cost Effectiveness =	$9,690	per ton of NOx removed in 2023 dollars

State	Facility Name	Facility ID	Unit ID	Year	Program Code	County	Source Category	Latitude	Longitude	Owner/Operator	Unit Type	Primary Fuel Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Commercial Operation Date	Operating Status	Max Hourly HI Rate (mmBtu/hr)	Associated Generators & Nameplate Capacity (MWe)
NV	North Valmy	8224	1	2023	ARP, MATS	Humboldt County	Electric Utility	40.8831	-117.1542	Idaho Power Company (Owner),Sierra Pacific Pc	Dry bottom wall-fired boiler	Coal		Low NOx Burner Technology (Dry Bottom only)	Baghouse		12/11/1981	Operating	2750	254.3
NV	North Valmy	8224	2	2023	ARP, MATS	Humboldt County	Electric Utility	40.8831	-117.1542	Idaho Power Company (Owner),Sierra Pacific Pc	Dry bottom wall-fired boiler	Coal	Dry Lime FGD	Low NOx Burner Technology (Dry Bottom only)	Baghouse		5/21/1985	Operating	3050	267

State	Facility Name	Facility ID	Unit ID	Year	Sum of the Operating Time	Gross Load (MWh)	Gross Load (MWh)	SO2 Mass (short tons)	SO2 Rate (lbs/mmBtu)	Calculated SO2 Rate (lbs/mmBtu)	CO2 Mass (short tons)	CO2 Rate (short tons/mmBtu)	NOx Mass (short tons)	NOx Rate (lbs/mmBtu)	Calculated NOx Rate (lbs/mmBtu)	Heat Input (mmBtu)	Heat Rate (mmBtu/ MWh)	Primary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
NV	North Valmy	8224	2	2019	4,200	709,566	169	516.7	0.153	0.156	692,557	0.105	1,024	0.289	0.310	6,603,367	9.3	Coal	Dry bottom	Dry Lime F(	Low NOx B	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2020	4,341	642,581	148	460.7	0.145	0.149	646,893	0.105	967	0.301	0.314	6,167,956	9.6	Coal	Dry bottom	Dry Lime F(	Low NOx B	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2021	6,668	1,177,825	177	747.0	0.129	0.131	1,193,194	0.105	1,455	0.251	0.256	11,376,761	9.7	Coal	Dry bottom	Dry Lime F(	Low NOx B	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2022	6,650	943,747	142	736.2	0.148	0.155	994,714	0.105	1,241	0.249	0.262	9,484,308	10.0	Coal	Dry bottom	Dry Lime F(	Low NOx B	Baghouse		ARP, MATS
NV	North Valmy	8224	2	2023	5,728	670,476	117	493.8	0.134	0.141	735,881	0.105	932	0.261	0.266	7,016,429	10.5	Coal	Dry bottom	Dry Lime F(	Low NOx B	Baghouse		ARP, MATS

Conversions for NH3 Reagent Costs (if given NH3 costs in $/ton using USGS source referenced in CCM**)

99.5 % Anhydrous conversion from pure NH3:	
480	$/ton pure NH3
0.24	$/lb pure NH3
9.16	$/ft3 (Anhydrous) density
1.22	$/gal NH3
1.22	$/gal 99.5% NH3 solution

NH3 Densities:

19% Aqueous:	57.3	lb/ft3
29% Aqueous:	56.1	lb/ft3
99.5% Anhydrous:	38.15	lb/ft3
50% Urea:	71	lb/ft3

Conversions:

1 ft3 = 7.48 gallons

Pure NH3/Urea Costs:	480	$/ton** — Enter USGS commodity price & yr here.
Commodity Year:	2023	Enter USGS commodity cost year here.
Select NH3/Urea Type:	19% Aqueous	

29.4% Aqueous conversion from pure NH3:	
480	$/ton pure NH3
0.24	$/lb pure NH3
13.46	$/ft3 (29% Aqueous) density
1.80	$/gal NH3
0.529	$/gal 29% NH3 solution

19% Aqueous conversion from pure NH3:	
480	$/ton pure NH3
0.24	$/lb pure NH3
13.75	$/ft3 (19% Aqueous) density
1.84	$/gal NH3
0.349	$/gal 19% NH3 solution

50% Urea Conversion	
480	$/ton Urea
0.24	$/lb Urea
17.04	$/ft3 Urea
2.28	$/gal Urea
1.139	$/gal 50% Urea Solution

Calculation Checks - See CCM Table 2.2 & Example Problem #1:

266	$/ton NH3
78.1	$/ton 29% aqueous solution
0.039	$/lb
2.19	$/ft3
0.293	$/gal
700	$/ton Urea
349.8	$/ton 50% Urea solution
0.175	$/lb
12.42	$/ft3
1.660	$/gal

***Assumes 2016 Cost Year** - This is the Minerals Commodity Summaries Cost Year Used in EPA Example Problem #1

I used this to double check the math for the conversions from $/ton to $/gal percent solution. EPA CCM default assumption is $0.293/gal for 29% solution and $1.660/gal for urea.

**USGS NH3 commodity price statistics (cited in CCM SCR Chapter): https://www.usgs.gov/centers/nmic/nitrogen-statistics-and-information

99.5 % Anhydrous
29.4% Aqueous
19% Aqueous
50% Urea

Air Pollution Control Cost Estimation Spreadsheet
For Selective Catalytic Reduction (SCR)

U.S. Environmental Protection Agency
Air Economics Group
Health and Environmental Impacts Division
Office of Air Quality Planning and Standards

(June 2019)

This spreadsheet allows users to estimate the capital and annualized costs for installing and operating a Selective Catalytic Reduction (SCR) control device. SCR is a post-combustion control technology for reducing NO_x emissions that employs a metal-based catalyst and an ammonia-based reducing reagent (urea or ammonia). The reagent reacts selectively with the flue gas NO_x within a specific temperature range to produce N_2 and water vapor.

The calculation methodologies used in this spreadsheet are those presented in the U.S. EPA's Air Pollution Control Cost Manual. This spreadsheet is intended to be used in combination with the SCR chapter and cost estimation methodology in the Control Cost Manual. For a detailed description of the SCR control technology and the cost methodologies, see Section 4, Chapter 2 of the Air Pollution Control Cost Manual (as updated March 2019). A copy of the Control Cost Manual is available on the U.S. EPA's "Technology Transfer Network" website at: http://www3.epa.gov/ttn/catc/products.html#cccinfo.

The spreadsheet can be used to estimate capital and annualized costs for applying SCR, and particularly to the following types of combustion units:

(1) Coal-fired utility boilers with full load capacities greater than or equal to 25 MW.
(2) Fuel oil- and natural gas-fired utility boilers with full load capacities greater than or equal to 25 MW.
(3) Coal-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.
(4) Fuel oil- and natural gas-fired industrial boilers with maximum heat input capacities greater than or equal to 250 MMBtu/hour.

The size and costs of the SCR are based primarily on five parameters: the boiler size or heat input, the type of fuel burned, the required level of NOx reduction, reagent consumption rate, and catalyst costs. The equations for utility boilers are identical to those used in the IPM. However, the equations for industrial boilers were developed based on the IPM equations for utility boilers. This approach provides study-level estimates (±30%) of SCR capital and annual costs. Default data in the spreadsheet is taken from the SCR Control Cost Manual and other sources such as the U.S. Energy Information Administration (EIA). The actual costs may vary from those calculated here due to site-specific conditions. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from system suppliers. The methodology used in this spreadsheet is based on the U.S. EPA Clean Air Markets Division (CAMD)'s Integrated Planning Model (IPM) (version 6). For additional information regarding the IPM, see the EPA Clean Air Markets webpage at http://www.epa.gov/airmarkets/power-sector-modeling. The Agency wishes to note that all spreadsheet data inputs other than default data are merely available to show an example calculation.

Instructions

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will clear many of the input cells and reset others to default values.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SCR is for new construction or retrofit of an existing boiler. If the SCR will be installed on an existing boiler, enter a retrofit factor between 0.8 and 1.5. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you select fuel oil or natural gas, the HHV and NPHR fields will be prepopulated with default values. If you select coal, then you must complete the coal input box by first selecting the type of coal burned from the drop down menu. The weight percent sulfur content, HHV, and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided. Method 1 is pre-selected as the default method for calculating the catalyst replacement cost. For coal-fired units, you choose either method 1 or method 2 for calculating the catalyst replacement cost by selecting appropriate radio button.

Step 4: Complete all of the cells highlighted in yellow. If you do not know the catalyst volume ($Vol_{catalyst}$) or flue gas flow rate ($Q_{flue\ gas}$), please enter "UNK" and these values will be calculated for you. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.005 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Natural Gas

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty. 1

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? 267 MW
CAMPD

What is the higher heating value (HHV) of the fuel? 1,033 Btu/scf
*HHV value of 1033 Btu/scf is a default value. See below for data source. Enter actual HHV for fuel burned, if known.

What is the estimated actual annual MWhs output? 670,476 MWhs
CAMPD 2023

Enter the net plant heat input rate (NPHR) 11.584 MMBtu/MW
NVE 4FA

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation 4455 Feet above sea level
NVE 4FA

Not applicable to units burning fuel oil or natural gas

Type of coal burned: Not Applicable

Enter the sulfur content (%S) = percent by weight

Not applicable to units buring fuel oil or natural gas

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the ***Cost Estimate*** tab. Please select your preferred method:

- ○ Method 1
- ○ Method 2
- ● Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	239 days	239 CAMPD 2023	
Number of days the boiler operates (t_{plant})	239 days		
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1355 lb/MMBtu	AP-42	
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0272 lb/MMBtu	CAMPD 2023	
Stoichiometric Ratio Factor (SRF)	1.050		

*The SRF value of 1.05 is a default value. User should enter actual value, if known.

Number of SCR reactor chambers (n_{scr})	1	
Number of catalyst layers (R_{layer})	3	
Number of empty catalyst layers (R_{empty})	1	
Ammonia Slip (Slip) provided by vendor	2	ppm
Volume of the catalyst layers ($Vol_{catalyst}$) (Enter "UNK" if value is not known)		Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)		acfm

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours
Estimated SCR equipment life	30	Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Gas temperature at the SCR inlet (T)	650	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})		ft^3/min-MMBtu/hour

Concentration of reagent as stored (C_{stored})	19	percent
Density of reagent as stored (ρ_{stored})	58	lb/cubic feet
Number of days reagent is stored ($t_{storage}$)	14	days

Densities of typical SCR reagents:		
50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Select the reagent used: Ammonia

Enter the cost data for the proposed SCR:

Desired dollar-year	2023		
CEPCI for 2023	797.9	Enter the CEPCI value for 2023 — 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	6.95	Percent	NVE 4FA
Reagent ($Cost_{reag}$)	0.349	$/gallon for 19% ammonia	USGS 2023
Electricity ($Cost_{elect}$)	0.0754	$/kWh	NVE 4FA
Catalyst cost ($CC_{replace}$)	254.85	$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	NVE 4FA
Operator Labor Rate	73.36	$/hour (including benefits)	NVE 4FA
Operator Hours/Day	4.00	hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution 'ammonia cost for 29% solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Percent sulfur content for Coal (% weight)		Not applicable to units burning fuel oil or natural gas	
Higher Heating Value (HHV) (Btu/lb)	1,033	2016 natural gas data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units	
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	3,093	MMBtu/hour	3050 mmBtu/hr
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	2,338,920	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		670,476	MWhs	7,016,429 mmBtu/yr
Heat Rate Factor (HRF) =	NPHR/10 =	1.16		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.287	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	2511	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	79.9	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	335.12	lb/hour	419 lb/hr uncontrolled
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	420.76	tons/year	526.3 tpy uncontrolled
NO_x removal factor (NRF) =	EF/80 =	1.00		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	#VALUE!	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	#VALUE!	/hour	
Residence Time	1/V_{space}	#VALUE!	hour	
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.18		
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	12.5	psia	
Retrofit Factor (RF)	Retrofit to existing boiler	1.00		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.2254	Fraction

Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_B \times EF_{adj} \times Slipadj \times NOx_{adj} \times S_{adj} \times (T_{adj}/N_{scr})$	11,396.12	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	#VALUE!	ft^2
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	#VALUE!	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	#VALUE!	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	#VALUE!	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	#VALUE!	feet

Reagent Data:

Type of reagent used	Ammonia	Molecular Weight of Reagent (MW) =	17.03 g/mole
		Density =	58 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	130	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/Csol$ =	685	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	88	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	29,800	gallons (storage needed to store a 14 day reagent supply rounded to th

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1$ = Where n = Equipment Life and i= Interest Rate	0.0802

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x $(CoalF \times HRF)^{0.43}$ = where A = Bmw for utility boilers	1592.79	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Oil and Natural Gas Boilers

For Oil and Natural Gas-Fired Utility Boilers between 25MW and 500 MW:

$$TCI = 86{,}380 \times (200/B_{MW})^{0.35} \times B_{MW} \times ELEVF \times RF$$

For Oil and Natural Gas-Fired Utility Boilers >500 MW:

$$TCI = 62{,}680 \times B_{MW} \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers between 275 and 5,500 MMBTU/hour :

$$TCI = 7{,}850 \times (2{,}200/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers between 205 and 4,100 MMBTU/hour :

$$TCI = 10{,}530 \times (1{,}640/Q_B)^{0.35} \times Q_B \times ELEVF \times RF$$

For Oil-Fired Industrial Boilers >5,500 MMBtu/hour:

$$TCI = 5{,}700 \times Q_B \times ELEVF \times RF$$

For Natural Gas-Fired Industrial Boilers >4,100 MMBtu/hour:

$$TCI = 7{,}640 \times Q_B \times ELEVF \times RF$$

Total Capital Investment (TCI) =	$36,124,635	in 2023 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$777,963	in 2023 dollars
Indirect Annual Costs (IDAC) =	$2,901,467	in 2023 dollars
Total annual costs (TAC) = DAC + IDAC	$3,679,431	in 2023 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	0.005 x TCI =	$180,623	in 2023 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$77,551	in 2023 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$301,579	in 2023 dollars
Annual Catalyst Replacement Cost =		$218,210	in 2023 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF		
Direct Annual Cost =		$777,963	in 2023 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$4,271	in 2023 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$2,897,196	in 2023 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$2,901,467	in 2023 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$3,679,431	per year in 2023 dollars
NOx Removed =	421	tons/year
Cost Effectiveness =	$8,745	per ton of NOx removed in 2023 dollars

Appendix E.2 – U. S. Forest Service

From:	Mcneel, Pleasant - FS, UT
To:	Nicholas Schlafer
Cc:	Ken McIntyre
Subject:	RE: [External Email]Nevada Regional Haze Revision
Date:	Tuesday, June 18, 2024 3:33:55 PM
Attachments:	

WARNING - This email originated from outside the State of Nevada. Exercise caution when opening attachments or clicking links, especially from unknown senders.

Nick,

The USDA Forest Service will not be submitting formal comments for the NV DEQ draft Regional Haze Sip Revision. I was unfortunately out sick during the time I had allotted for my review, and so was not able to give the document the time deserved .

I did a cursory review of the document and the responses from EPA Region 9 and the National Park Service. I concur with the EPA Region 9 and the NPS assessment that their suggested changes to the analysis would likely support Selective Catalytic Reduction (SCR) as cost-effective for North Valmy Units. I will defer my detailed review to the NSR permitting process, when North Valmy facility submits their PSD application.

I appreciate the work you are doing and look forward to continued involvement in review of the changes planned for these facilities. I appreciated the continued proactive engagement by the Nevada DEQ, particularly the 04Jun24 meeting, and look forward to continuing to working with your staff in the future.

Cheers,
Pleas

Pleasant J McNeel IV, PE
Regional Air Program Manager
Forest Service
Intermountain Region (R4)
cell: 801.247.8892
pleasant.mcneel@usda.gov
www.fs.fed.us

Caring for the land and serving people

Appendix E.3 – U. S. Fish and Wildlife Service

From: Allen, Tim
To: Nicholas Schlafer
Cc: Ken McIntyre
Subject: Re: [EXTERNAL] Nevada Regional Haze Revision
Date: Monday, June 17, 2024 8:08:20 AM

WARNING - This email originated from outside the State of Nevada. Exercise caution when opening attachments or clicking links, especially from unknown senders.

Hi Nick,

At this time, I do not have comments to provide. My Class I areas are fairly distant from Nevada.

Thank you for checking,
Tim

From: Nicholas Schlafer <n.schlafer@ndep.nv.gov>
Sent: Monday, June 17, 2024 8:22 AM
To: Allen, Tim <tim_allen@fws.gov>
Cc: Ken McIntyre <kmcintyre@ndep.nv.gov>
Subject: [EXTERNAL] Nevada Regional Haze Revision

This email has been received from outside of DOI - Use caution before clicking on links, opening attachments, or responding.

Tim,

We did not receive any formal comments from Fish & Wildlife regarding our draft Regional Haze Sip Revision. Do you plan on submitting comments on our revision or can you confirm that you do not have any for us?

Thank you,
Nick

Nicholas Schlafer
Environmental Scientist
Planning/Data Management Branch, Bureau of Air Quality Planning
Nevada Division of Environmental Protection
Department of Conservation and Natural Resources
901 S. Stewart Street, Suite 4001
Carson City, NV 89701
n.schlafer@ndep.nv.gov
(O) 775-687-9354 | (F) 775-687-5856

Appendix E.4 – Bureau of Land Management

From:	Giles, Franklin E
To:	Nicholas Schlafer
Cc:	Ken McIntyre
Subject:	Re: [EXTERNAL] Nevada Regional Haze Revision
Date:	Friday, June 21, 2024 7:06:25 AM

Nick,

Thanks for your email. BLM does not have any comments at this time.

Best Regards,

Frank

Get Outlook for iOS

From: Nicholas Schlafer <n.schlafer@ndep.nv.gov>
Sent: Monday, June 17, 2024 7:31:20 AM
To: Giles, Franklin E <fgiles@blm.gov>
Cc: Ken McIntyre <kmcintyre@ndep.nv.gov>
Subject: [EXTERNAL] Nevada Regional Haze Revision

Frank,

We did not receive any formal comments from the Bureau of Land Management regarding our draft Regional Haze Sip Revision. You had mentioned in our call on June 4th that you were reviewing our revision and may send us a response. Should we expect comments on our revision, or can you confirm that you do not have any for us?

Thank you,
Nick

Planning/Data Management Branch, Bureau of Air Quality Planning
Nevada Division of Environmental Protection
Department of Conservation and Natural Resources
901 S. Stewart Street, Suite 4001
Carson City, NV 89701
n.schlafer@ndep.nv.gov
(O) 775-687-9354 | (F) 775-687-5856

NEVADA DIVISION OF ENVIRONMENTAL PROTECTION

Nevada Department of CONSERVATION & NATURAL RESOURCES

Connect with us:

Appendix F – NV Energy Response Letter 9

July 24, 2024

Mr. Nicholas Schlafer
Nevada Division of Environmental Protection
Department of Conservation and Natural Resources
901 S. Stewart Street, Suite 4001
Carson City, NV 89701

RE: Response to Request for Additional Information
Regional Haze Reasonable Further Progress: Updated Four Factor Analysis
NV Energy North Valmy and Tracy Generating Stations

Dear Mr. Schlafer,

Per our discussions on June 25 and 27, 2024, NV Energy hereby provides responses Nevada Divisions of Environmental Protection (NDEP) requests for additional information related to certain Environmental Protection Agency Region 9 technical comments dated June 14, 2024 and National Park Service technical comments dated June 5, 2024 on Nevada's draft Regional Haze State Implementation Plan for the Second Planning Period.

NV Energy appreciates the opportunity to work with the Nevada Division of Environmental Protection in this endeavor. Please feel free to contact Chris Heintz (702-402-2048) if you have any questions or need further information.

Sincerely,

Mathew Johns
Vice President, Environmental Services and Land Management
NV Energy

cc: Andrew Tucker (atucker@ndep.nv.gov)
Ken McIntyre (kmcintyre@ndep.nv.gov)
Jason Hammons (jason.hammons@nvenergy.com)
Chris Heintz (christopher.heintz@nvenergy.com)

June 2024 NDEP Requests for Additional Information

The following NDEP requests for additional information were identified during our discussions on June 25 and June 27, 2024, based on certain Environmental Protection Agency Region 9 technical comments dated June 14, 2024, and National Park Service technical comments dated June 5, 2024, on Nevada's draft Regional Haze State Implementation Plan for the Second Planning Period.

NDEP Request 1: Please provide the forecasted generation data used to prepare Section 1.1.2, Figure 1, in the updated Four Factor Analysis.

Attachment 1 to this response letter provides a tabulation of forecasted generation data for 2028 to 2030 for NV Energy and Idaho Power forecast used to create Figure 1. The scenarios included are discussed in Section 1.1.2 of the updated Four-Factor analysis.

NDEP Request 2: Please provide a NV Energy's recommendation for the time necessary to complete the conversion of the Valmy units from coal to natural gas generation.

As discussed on June 27, 2024, NV Energy recommends using June 1, 2027, as a compliance date to complete conversion of the units to natural gas operation.

The proposed date provides a 12-month buffer in the event unforeseeable and uncontrollable factors impact the currently planned schedule for the natural gas conversion.

NDEP Request 3: Please recommend a consistent terminology for the Tracy Unit 4/5 for use in the updated State Implementation Plan

NV Energy supports the use of consistent terminology and recommends the use of Tracy Unit #4 Piñon Pine for the purposes of the updated State Implementation Plan. This is the name designating the unit in the facility's current Title V Operating Permit. Tracy Unit #4 Piñon Pine is a combustion turbine with a heat recovery steam generator (HRSG), it is equipped with duct burners and exhausts through one stack. It's important to note that other names may continue to be used in other permits, documents, or communications and that those documents don't need to be updated. Below is a summary of various names referring to Tracy Unit #4 Piñon Pine:

- Tracy 4 (Piñon CT)
- Tracy 5 (Piñon HRSG)
- Tracy 4/5 (Piñon CT and HRSG)
- Tracy 6 (Tracy 4 Piñon CT)
- Tracy 7 (Tracy 5 Piñon HRSG)

All these names have historically and or are currently being used by various agencies or communications including, but not limited to, the Securities and Exchange Commission, Federal Energy Regulatory Commission, the Environmental Protection Agency, the Energy Information Administration, Public Utilities Commission of Nevada, Federal Trade Commission Bureau of Consumer Protection, the Nevada Division of Environmental Protection and others.

June 2024 NDEP Requests for Additional Information

NDEP request 4: In draft control determination language, NDEP used basis for 0.11 lb/MMBtu emissions limit for the Valmy units whereby the emission limit used in cost calculations was 0.102 lb./MMBtu. Please clarify which emission limit is appropriate and how it was derived.

As discussed during our June 25, 2024, call it appears NDEP simply rounded-up to two significant digits. NV Energy does not have any concerns with using the actual emissions limit used in the updated Four-Factor analysis for final control determination purposes.

The proposed emission limit, with rounding to four decimal places is 0.1029 lb/MMBtu. This is derived by using an emission factor from EPA's Emissions Factors and Quantification, AP42, Fifth Edition, Volume 1: External Combustion Sources, Section 1.4 Natural Gas Combustion, Table 1.4-1 – Large Wall-Fired Boiler (>100 MMBtu/hr heat input), Controlled – Low NO_x burners. The listed emission factor is 140 (lb/10^6 scf). Footnote "a", in partial, states "Emission factors are based on an average natural gas heating value of 1,020 Btu/scf. To convert from lb/10^6 scf to lb/MMBtu, divide by 1,020". 140 / 1020 = 0.13725 or 0.1373 lb/MMBtu. As stated in the Updated Four Factor Analysis, the estimated NO_x control performance for selective non-catalytic reduction (SNCR) is estimated at 25%. Therefore taking 0.13725 lb/MMBtu and multiplying by (1-0.25) = 0.10294 or 0.1029 lb/MMBtu.

NDEP request 5: In draft control determination language, NDEP used basis for 0.0148 lb/MMBtu emissions limit for the Tracy Piñon Unit Please clarify how this emission limit was derived.

As stated in the Updated Four Factor Analysis, Section 5.2, selective catalytic reduction (SCR) with 90% reduction would achieve 4.1 ppm @15% O_2 NO_x emissions.

Using EPA Test Method 19, Equation 19-1, the emission rate in lb/MMBtu is calculated as follows:

NO_x ppm * NO_x conversion factor to lbs/scf * dry based F-Factor in units of dscf/10^6 Btu * 20.9/(20.9 – O_2%), where:

> NO_x ppm = 4.1
> NO_x conversion factor = 1.194E-7 (Table 19-1)
> F_d-Factor, natural gas = 8,710 (Table 19-2)
> O_2 = 15% (calculating at 15% O_2)

4.1*1.194E-7*8,710*20.9/(20.9-15) = 0.0151 lb/MMBtu

June 2024 NDEP Requests for Additional Information

NDEP Request 6: The Environmental Protection Agency noted in their June 14, 2024, comments the need to document NV Energy's "current firm-specific overall cost of capital approved by the PUCN" (Section A.b.i, page 2)

Appendix C of the updated Four Factor analysis provides the specific PUCN approval for the current cost of capital for NV Energy operating utility, Sierra Pacific Power Company (SPPC), for which the Tracy Generating Station and North Valmy Generating Station are operated under.

In the most recent approved General Rate Case from 2022 the Public Utilities Commission of Nevada approved SPPC's cost of capital at 6.95%. A hyperlink to the commission order, signed February 16, 2023, is provided below. Paragraph 71 (see excerpt from the commission order below) of this order notes the commission approval for this cost of capital.

https://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2020_THRU_PRESENT/2022-6/24156.pdf

71. The Commission finds, based upon the evidence in the record and as proposed by Staff, that the range of reasonableness for SPPC's ROE falls between 9.10% - 9.90%, and approves an ROE of 9.50%, which is within that range. In conjunction with its approval of an ROE of 9.50%, the Commission is approving Staff's 6.95% recommended overall cost of capital, based on Staff's recommended 9.50% ROE and 52.40% equity ratio. The Commission finds that an ROE of 9.50% with an equity ratio of 52.40% is just and reasonable, as the Commission will explain below. The Commission notes that it is approving a 6.95% overall cost of capital because, as *Hope* and *Bluefield* lay out, it is the overall end result of the total cost of capital that the Commission is approving as just and reasonable.

NDEP Request 7: The Environmental Protection Agency Region 9 recommended a 30-day boiler averaging period verses a 12-month rolling average basis for NOx emissions limit.

NV Energy accepts the 30-day boiler averaging period if used by NDEP as part of its control determination.

June 2024 NDEP Requests for Additional Information

Attachment 1

Forecast Data Used for Figure 1-North Valmy Generating Station – Projected Future Station Output, Updated Four Factor Analysis: North Valmy Generating Station, March 2024

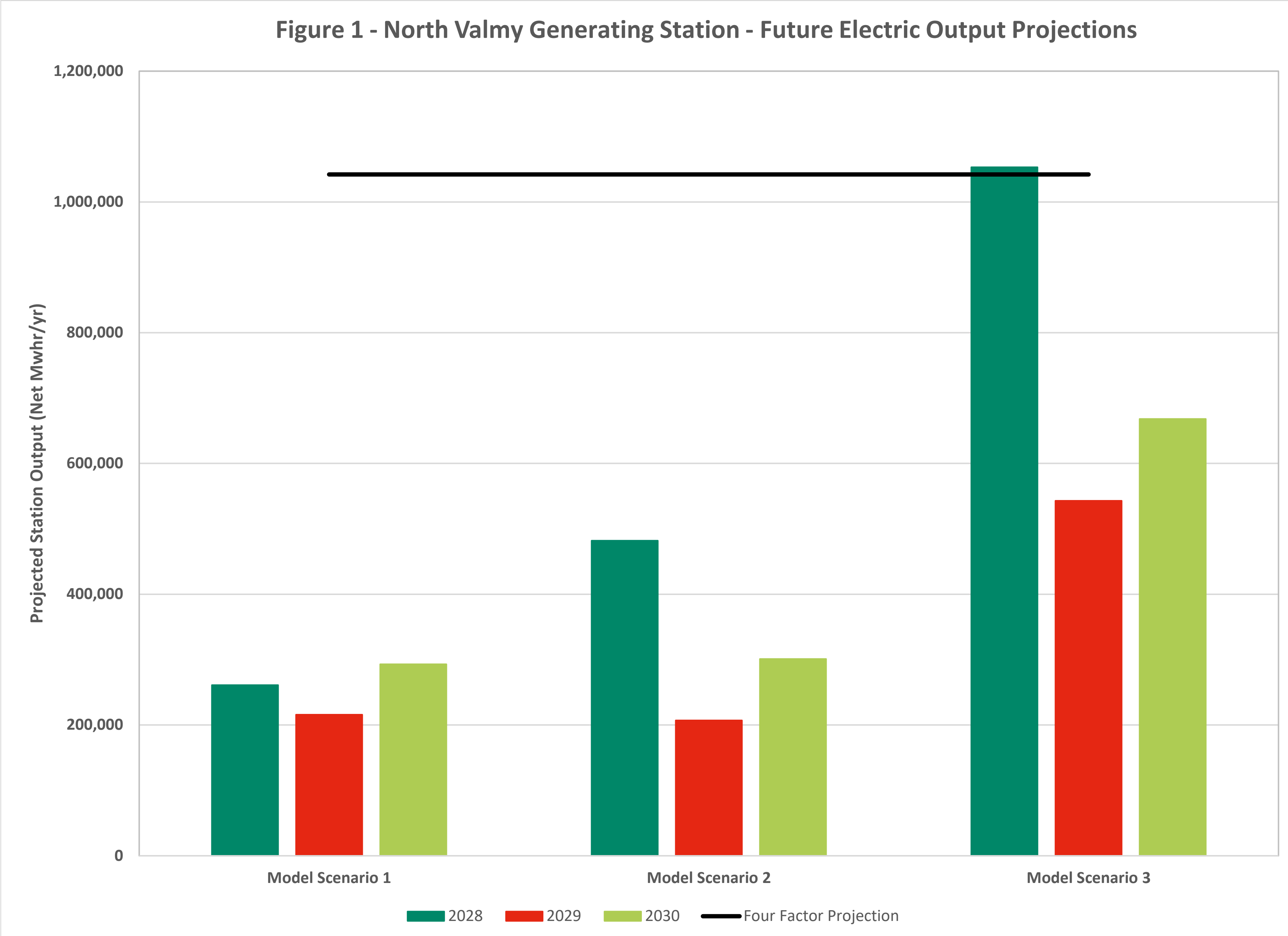


Figure 1 - North Valmy Generating Station - Future Electric Output Projections
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Projected Station Output (Net Mwhr/yr)
Model Scenario 1
Model Scenario 2
Model Scenario 3
2028
2029
2030
Four Factor Projection

Model 1 Scenario Backup Data
North Valmy Generating Station Forecasted Net Generation
Units 1 and 2 Converted to Natural Gas Operation

Ln		NV Energy Forecast[1]			Idaho Power Company Forecast[2]			Total Forecast			Ln
No	Year	Unit 1	Unit 2	Total	Unit 1	Unit 2	Total	Unit 1	Unit 2	Total	No
1	2028	43,346	48,135	91,481	100,622	69,109	169,731	143,968	117,244	261,212	1
2	2029	27,037	29,082	56,119	90,743	69,345	160,088	117,780	98,427	216,207	2
3	2030	7,764	18,927	26,691	149,004	117,675	266,679	156,768	136,602	293,370	3

Notes:
(1) NV Energy forecast based on Integrated Resource Plan 5th Amendment, Preferred Plan, Public Utilities Commission of Nevada, Docket No. 2023-08015.
(2) Idaho Power Company forecasted generation based on the Valmy optimized output modeled within its 2023 Integrated Resource Plan preferred portfolio. Provided to NV Energy January 5, 2024.

Model 2 Scenario Backup Data
North Valmy Generating Station Forecasted Net Generation
Units 1 and 2 Converted to Natural Gas Operation

Ln		NV Energy Forecast[1]			Idaho Power Company Forecast[2]			Total Forecast			Ln
No	Year	Unit 1	Unit 2	Total	Unit 1	Unit 2	Total	Unit 1	Unit 2	Total	No
1	2028	90,662	221,294	311,956	100,622	69,109	169,731	191,284	290,403	481,687	1
2	2029	22,756	23,694	46,449	90,743	69,345	160,088	113,499	93,039	206,537	2
3	2030	14,942	19,847	34,789	149,004	117,675	266,679	163,946	137,522	301,468	3

Notes:

(1) NV Energy forecast based on a resource plan modeling scenario with additional generating resources installed at Valmy for use by NV Energy.

(2) Idaho Power Company forecasted generation based on the Valmy optimized output modeled within its 2023 Integrated Resource Plan preferred portfolio. Provided to NV Energy January 5, 2024.

Model 3 Scenario Backup Data
North Valmy Generating Station Forecasted Net Generation
Units 1 and 2 Converted to Natural Gas Operation

Ln		NV Energy Forecast[1]			Idaho Power Company Forecast[2]			Total Forecast			Ln
No	Year	Unit 1	Unit 2	Total	Unit 1	Unit 2	Total	Unit 1	Unit 2	Total	No
1	2028	479,948	403,665	883,613	100,622	69,109	169,731	580,570	472,774	1,053,344	1
2	2029	65,289	317,703	382,992	90,743	69,345	160,088	156,032	387,048	543,080	2
3	2030	67,072	334,125	401,197	149,004	117,675	266,679	216,076	451,800	667,876	3

Notes:
(1) NV Energy forecast based on a resource plan modeling scenario with no new generating resources installed at Valmy for use by NV Energy.
(2) Idaho Power Company forecasted generation based on the Valmy optimized output modeled within its 2023 Integrated Resource Plan preferred portfolio. Provided to NV Energy January 5, 2024.