REVISION TO NEVADA'S REGIONAL HAZE 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)

NEVADA DIVISION OF
ENVIRONMENTAL
PROTECTION

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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the four-factor re-analysis and establishing new reasonable progress requirements, NDEP is now resubmitting the withdrawn elements as a revision to Nevada's Regional Haze State Implementation Plan.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

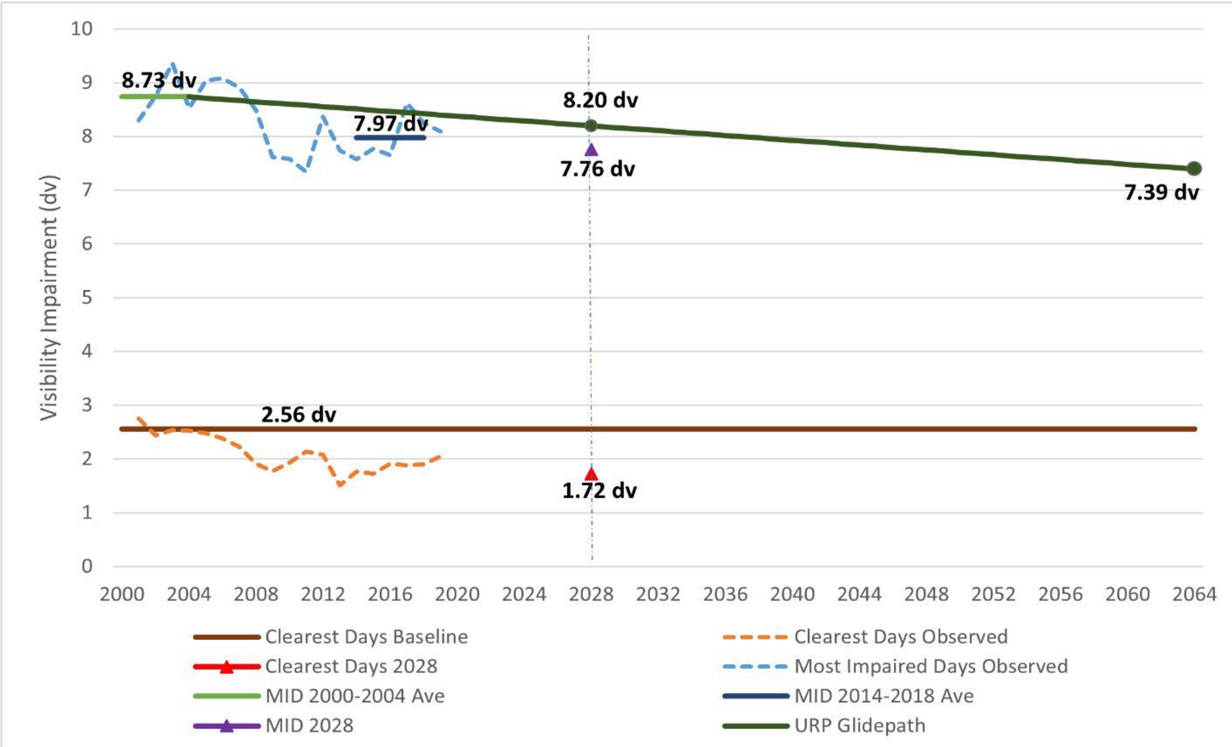
Significant emission reductions are expected to achieve reasonable progress for the second implementation period of Nevada's Regional Haze SIP. Nevada expects a total reduction in primary visibility impairing pollutants (SO_2, NO_x, and PM_{10}) of 4,187 tpy as a result of controls implemented during 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



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ACRONYMS, ABBREVIATIONS, AND TERMS

2028OTBa2	2028 On-the-Books/On-the-Way Emission Inventory Version 2
BLM	Bureau of Land Management
CAA	Clean Air Act
CEPCI	Chemical Engineering Plant Cost Index
CFR	Code of Federal Regulations
CIA	Class I Area
DLN	Dry Low NO_x
FGR	Flue Gas Recirculation
FLM	Federal Land Manager
FWS	Fish & Wildlife Service
GE	General Electric
IMPROVE	Interagency Monitoring of Protected Visual Environments
JARB1	Jarbidge Wilderness Area IMPROVE Monitor
LNB	Low-NO_x Burner(s)
LEV	Low-Emission Vehicle
LTS	Long-Term Strategy
MW	Megawatts
NAC	Nevada Administrative Code
NDEP	Nevada Division of Environmental Protection
NG	Natural Gas
NPS	National Park Service
NRS	Nevada Revised Statutes
OFA	Over-Fired Air
PUC	Public Utilities Commission
RH	Regional Haze
RHR	Regional Haze Rule
RPG	Reasonable Progress Goal(s)
SCR	Selective Catalytic Reduction
SEC	State Environmental Commission
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
USEPA	United States Environmental Protection Agency
USFS	United States Forest Service
URP	Uniform Rate of Progress
WA	Wilderness Area
WRAP	Western Regional Air Partnership

CHEMICALS AND CHEMICAL COMPOUNDS

NO_x	Oxides of Nitrogen
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)
SO_2	Sulfur Dioxide

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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.1
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
RE: 4-Factor update – NV Energy North Valmy	*Response Letter 10*	January 8, 2025	Appendix F
RE: Request for Additional Information, Public Comments on Four-Factor Analysis for the NV Energy North Valmy and Tracy Generating Stations	*Response Letter 11*	April 24, 2025	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. 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 $9,457/ton and $7,791/ton is estimated for Unit 1 and 2, respectively. The total annual cost of implementing SNCR on Unit 1 is estimated at $820,000 and is projected to reduce NO_x emissions by 86.2 tpy. For Unit 2, the cost of implementing SNCR is estimated at $890,000 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 $12,769/ton and $10,618/ton is estimated for Unit 1 and 2, respectively. The total annual cost of implementing SCR on Unit 1 is estimated at $3.44M and is projected to reduce NO_x emissions by 269.3 tpy. For Unit 2, the cost of implementing SCR is estimated at $3.80M 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	$820,000	$9,457/ton
	2	457.8 tpy NO_x	114.4 tpy NO_x	$890,000	$7,791/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	$3.44 Million	$12,769/ton
	2	457.8 tpy NO_x	357.7 tpy NO_x	$3.80 Million	$10,618/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.

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.

These emission limits and associated requirements, listed in regulation R138-24, are incorporated into the SIP by reference. NDEP posted notice on September 26, 2024, of a public workshop held on October 15, 2024, and accepted comments through the November 19, 2024, SEC hearing on R138-24. The regulation and associated documentation pertaining to North Valmy Generating Station's reasonable progress requirements can be found in Appendix C.1.

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.

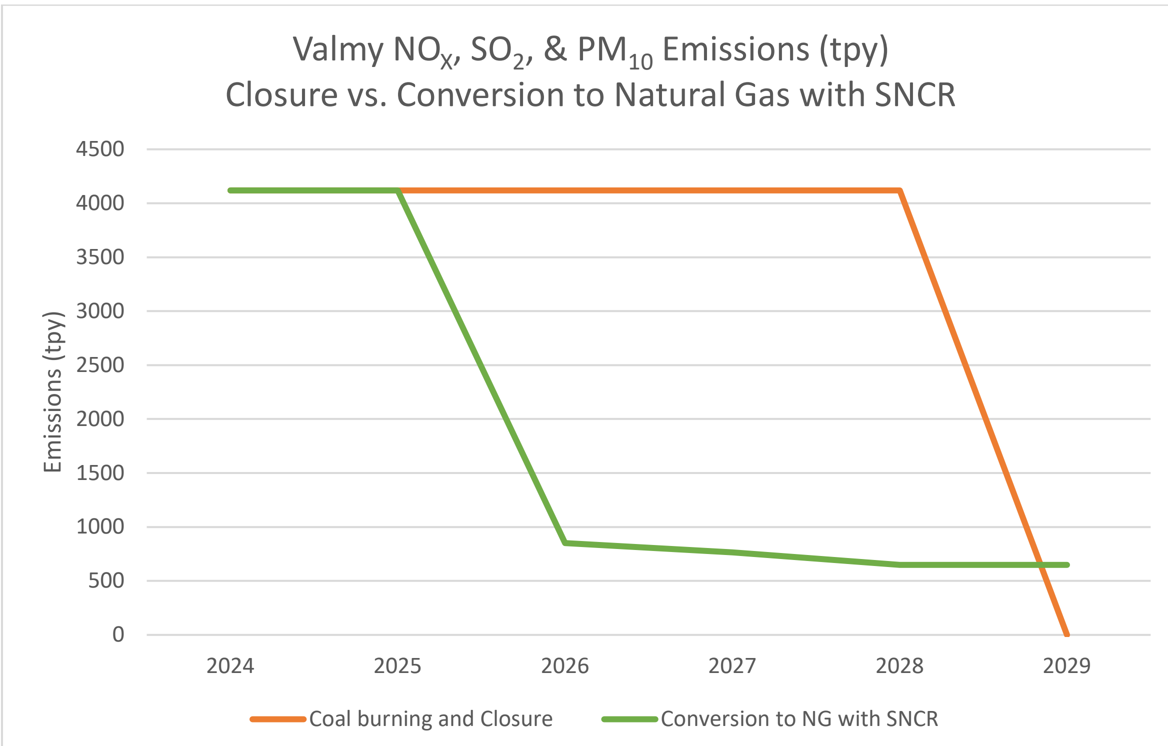
Table 2-5: Valmy Modeling vs. Final Emission Reductions During Second Round in TPY

	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		Appendix A.2
Nevada Regulation	Regulation	September 17, 2024	Appendix C.1
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
RE: Request for Additional Information, Public Comments on Four-Factor Analysis for the NV Energy North Valmy and Tracy Generating Stations	*Response Letter 11*	April 24, 2025	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 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 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 in Nevada's 2022 Regional Haze SIP submission and in this document, 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. Pages with referenced conditions in the Tracy Generating Station's permit that NDEP is relying on to achieve reasonable progress for the second implementation period can be found in Appendix A.2.

The emission limits and associated requirements, listed in regulation R138-24 and shown in Table 3-8, are incorporated into the SIP by reference. NDEP is relying on Section 5.2 of NV Energy's four-factor analysis (Appendix B) and *NV Energy's Response Letter 9* (Appendix F.1) for the derivation of the 0.0151 lb/MMBtu emission limit in Table 3-8. NDEP posted notice on September 26, 2024, of a public workshop held on October 15, 2024, and accepted comments through the November 19, 2024, SEC hearing on R138-24. The regulation and associated documentation pertaining to Tracy Generating Station's reasonable progress requirements can be found in Appendix C.1.

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

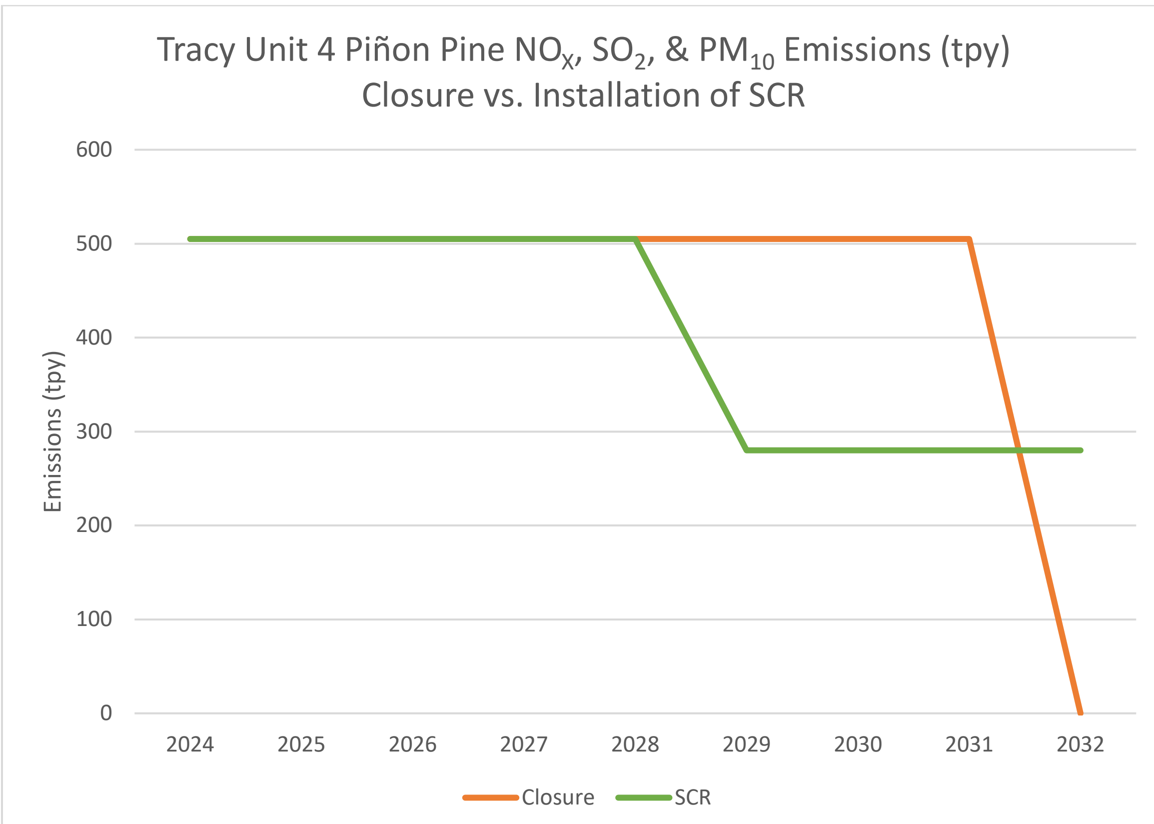
Table 3-10: Tracy Existing Controls for NO_x

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	Unit 4 Piñon Pine	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. The permit was again renewed on April 30, 2025, prior to final submittal of Nevada's 2025 Regional Haze SIP Revision. 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	Recordkeeping
	4.4.7 4.4.8 4.4.15 4.4.16	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.

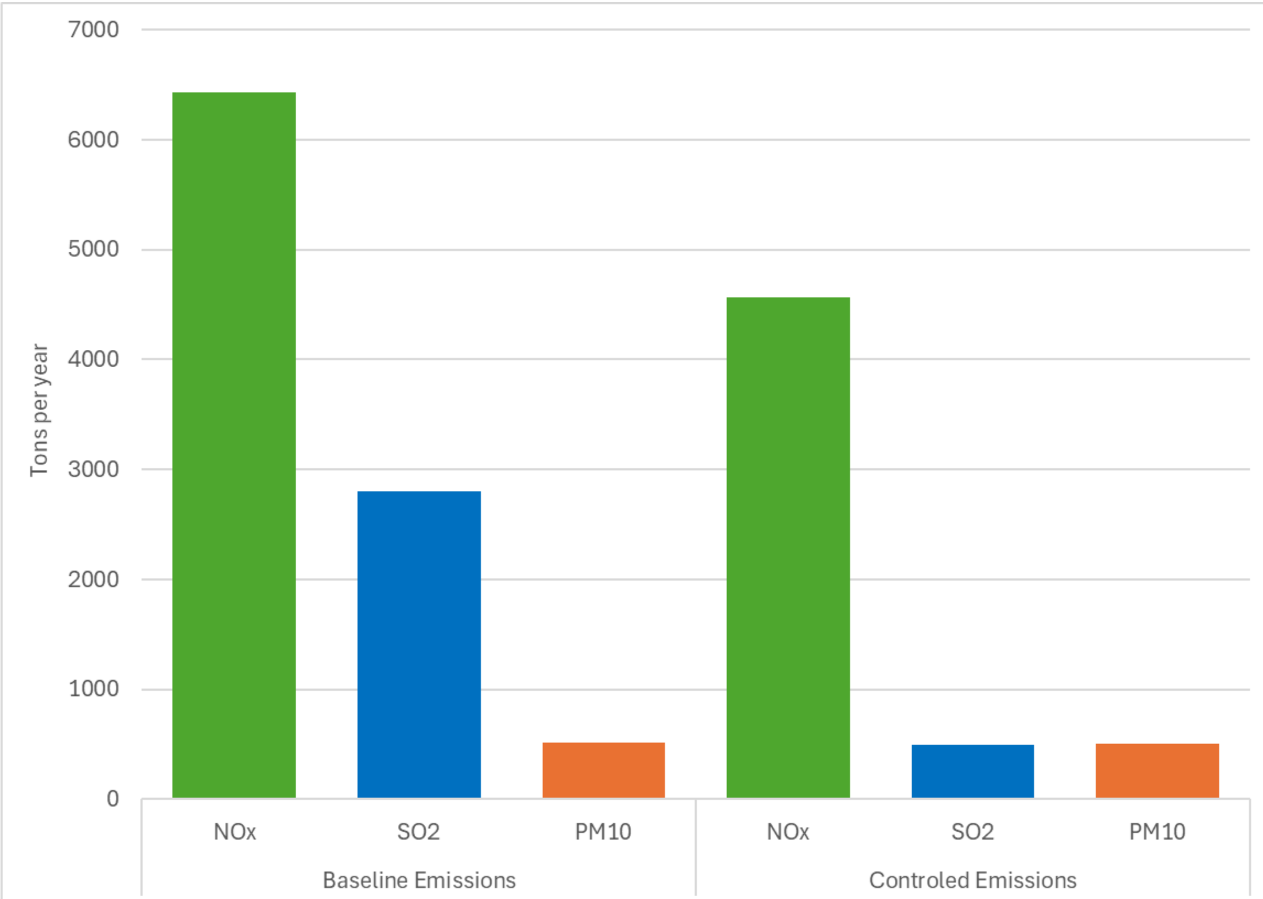
Emission reductions calculated from NDEP's four-factor analyses are more accurate than what was estimated for WRAP modeling and provide a better image of achieved emission reductions as a result of Nevada's efforts during the second implementation period. WRAP modeling inventories used less recent emissions 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

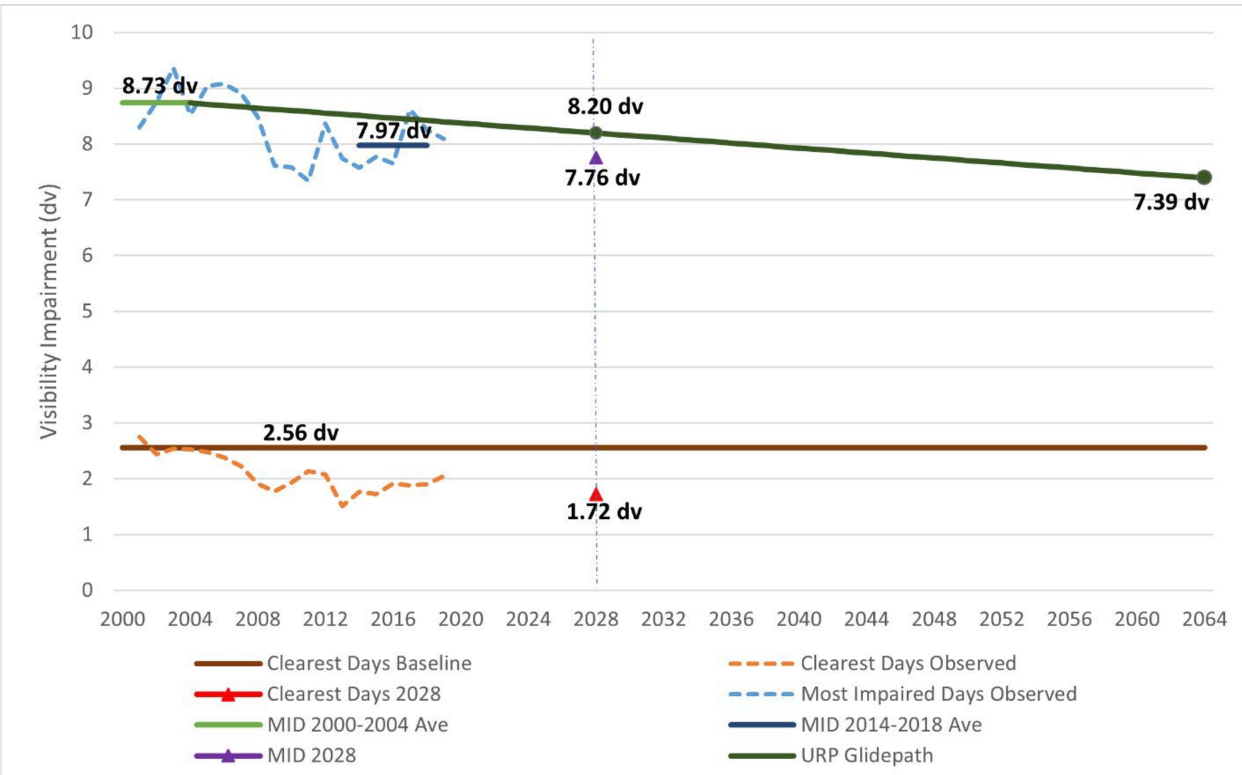


Table 5-4: Summary of Predicted Progress Toward 2028 Uniform Rate of Progress at JARB1 (Deciviews)

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 provided their own technical review and formal response submitted on June 5th, 2024, which 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 Idaho Power Company 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, the 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.

NDEP requested additional information from NV Energy supporting its capacity utilization, heat input values, CEPCI value and cost of ammonia reagent (Appendix F). While there have been variations in annual MWh output at North Valmy Generating Station since the 2016-2018 baseline, NDEP decided to retain the original baseline to maintain consistency with the baseline established in the SIP for the Regional Haze Round Second Planning Period. NDEP requested NV Energy update its four-factor analysis to include the final 2023 CEPCI value, these updated figures are included in Sections 2.3.1 and 2.3.2 of this SIP. After reviewing comments from the

NPS, Conservation Organizations, and NV Energy's responses to NDEP's request for additional information, NDEP does not find that SCR's cost effectiveness, for Unit 1 or 2 of the North Valmy Generating Station, meets the $10,000/ton threshold. Detailed feedback provided by the NPS for NDEP on the draft revision to the SIP for the second planning period and NDEP's final response to comments received can be found in Appendix E.

6.2 Public Comment

Per CAA section 110(l), SIP revisions are subject to reasonable notice and public hearing prior to adoption and submittal by states to the EPA. Additionally, CAA section 110(l) prohibits the EPA from approving any SIP revision that would interfere with any applicable requirement concerning attainment and reasonable further progress, or any other applicable requirement of the CAA. NDEP has satisfied the first requirement by holding a reasonable notice and 30-day Public Comment period for the draft Regional Haze SIP Revision prior to submittal to EPA. Furthermore, NDEP confirms that the contents of this SIP revision do not weaken or relax any pre-existing requirements of the CAA, and instead, strengthens the requirements through emission reductions achieved from the implementation of new control measures.

Pursuant to 40 CFR 51.102, NDEP made its draft Nevada Regional Haze SIP Revision available for public review beginning February 28, 2025. Notice was given that a hearing was scheduled for April 4, 2025, contingent on NDEP receiving a written request for a hearing. NDEP welcomed written public comments and requests to hold a hearing until March 31, 2025. The hearing scheduled for April 4, 2025, was later cancelled, as NDEP did not receive a request to hold the hearing. NDEP received comments from the following organizations.

- NV Energy on March 21, 2025.
- National Parks Conservation Association, Sierra Club, and Coalition to Protect America's National Parks (collectively, "Conservation Organizations") on March 31, 2025.

The Conservation Organizations provided their own technical review of implementing SCR at North Valmy Generating Station to control NO_X emissions finding it cost effective at $7,072/ton for Unit 1 and $5,567/ton for Unit 2 and commented that details of the four-factor analysis were unsupported. NDEP requested additional information from NV Energy supporting its four-factor analysis calculations (Appendix F). While there have been variations in annual MWh output at North Valmy Generating Station since the 2016-2018 baseline, NDEP decided to retain the original baseline to maintain consistency with the baseline established in the SIP for the Regional Haze Round Second Planning Period. NDEP requested NV Energy update its four-factor analysis to include the final 2023 CEPCI value, these updated figures are included in Sections 2.3.1 and 2.3.2 of this SIP.

After reviewing comments from the NPS, Conservation Organizations, and NV Energy's responses to NDEP's request for additional information NDEP does not find that SCR's cost effectiveness, for Unit 1 or 2 of the North Valmy Generating Station, meets the $10,000/ton threshold. Evidence of public participation and comments submitted to NDEP during the public notice period are provided in Appendix G. NDEP responses to comments received are provided in Appendix G.5.

7. REFERENCES

Jenkins, S. (2024). 2023 CEPCI annual average value decreases from previous year. *Chemical Engineering magazine,* https://www.chemengonline.com/2023-cepci-annual-average-value-decreases-from-previous-year/

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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.

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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

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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
North Las Vegas, Nevada 89036

ORIGINAL ISSUE DATE: August 3, 2022

FIRST REISSUE DATE: February 6, 2024

SECOND REISSUE DATE: April 30, 2025

CURRENT ACTION: ATC Administrative Revision

Issued to:
Lhoist North America of Arizona, Inc.
PO Box 363068
North Las Vegas, Nevada 89165

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, GHG, and a single HAP (HCl), and a minor source for total HAP and VOC. 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~~	~~339.34~~	~~203.17~~	~~1,901.34~~ ~~1,395.25~~[4]	~~968.90~~	~~1,646.76~~	~~8.46~~	~~22.96~~	~~21.12~~	~~697,494.80~~

[1] ~~The PTE in this table, taken from the Part 70 operating permit issued 11/16/2023, 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 Regional Haze SIP. This value is based on a reduction of 506.09 tons/year, identified in Table 7-1 of 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").~~

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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
CO_2e	carbon dioxide equivalent
DAQ	Division of Air Quality
DES	Clark County Department of Environment and Sustainability
EPA	U.S. Environmental Protection Agency
EU	emission unit
GHG	greenhouse gas
HAP	hazardous air pollutant
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	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxides
tlp	tons of lime produced
tpd	tons per day
U.S.C.	United States Code
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 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 kiln's rolling 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 state or federal holiday, or on any day the office is not normally open for business, 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 state or federal holiday, or on any day the office is not normally open for business, 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: *[AQR 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. *[AQR 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.~~

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

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 **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 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))~~

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

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.~~

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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 D-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 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 **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))~~

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.~~

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))~~

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

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_{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_{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 **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**~~

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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.~~

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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. <u>Calibration Error</u> (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. <u>Linearity Check</u> (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. <u>Relative Accuracy</u> (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. <u>Bias</u> (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. <u>Cycle Time</u> (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.

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~~

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

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~~

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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)~~

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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)~~

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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)~~

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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******

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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.~~

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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.~~

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.~~

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.
   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.

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.~~

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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 = 1.660×10^{-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.~~

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.

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.~~

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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 = 1.660×10^{-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.~~

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.

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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.

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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.

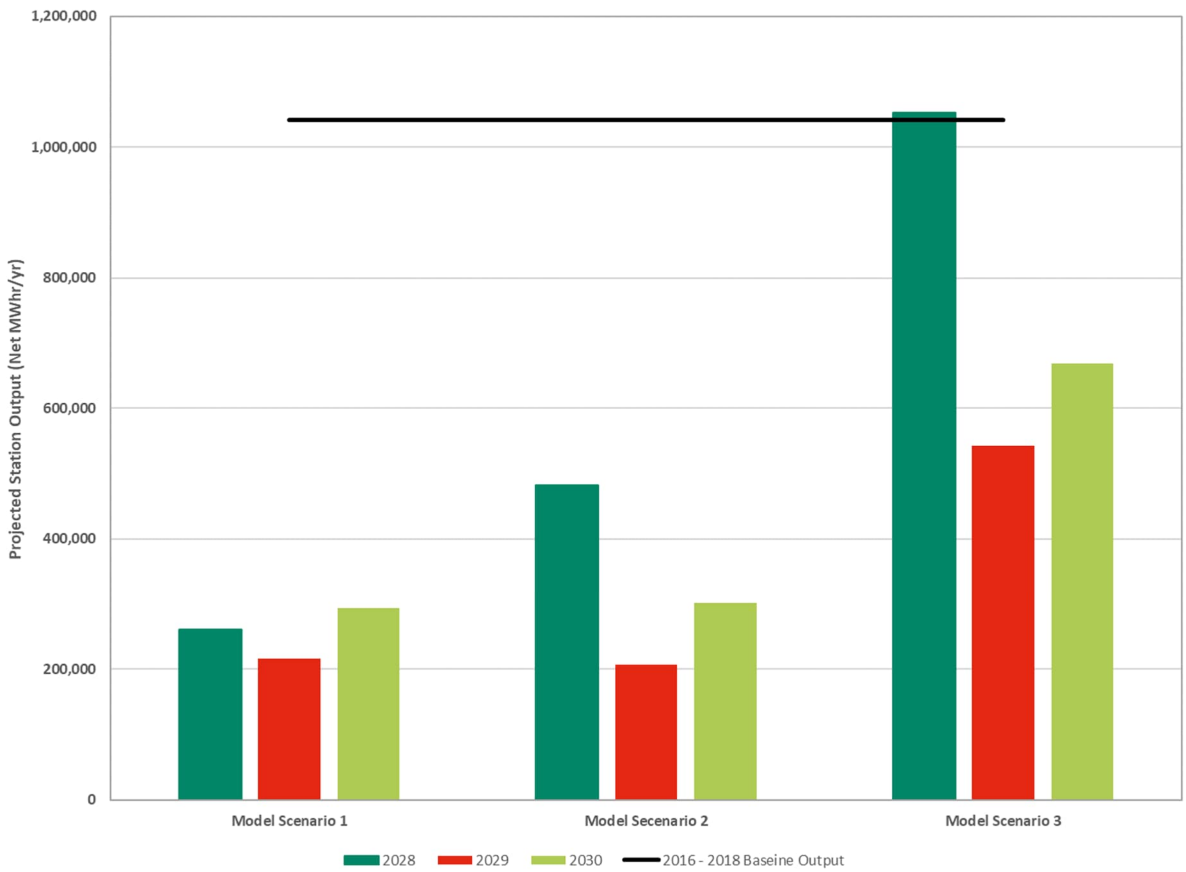
1.1.2 North Valmy Station Future Operating Profile

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	
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		

Plant Elevation 4455 Feet above sea level

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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (whre SR = 1 for NH_3; 2 for Urea)	65	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	341	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	44.0	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ 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) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	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) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.25	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/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 x (B_{MW} x HRF x CoalF)$^{0.78}$ x AHF x RF
For Coal-Fired Industrial Boilers:
APH_{cost} = 69,000 x (0.1 x Q_B x HRF x CoalF)$^{0.78}$ x AHF x 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 x (B_{MW})$^{0.33}$ x (NO_xRemoved/hr)$^{0.12}$ x BTF x RF
For Fuel Oil and Natural Gas-Fired Utility Boilers:
BOP_{cost} = 213,000 x (B_{MW})$^{0.33}$ x (NO_xRemoved/hr)$^{0.12}$ x RF
For Coal-Fired Industrial Boilers:
BOP_{cost} = 320,000 x (0.1 x Q_B)$^{0.33}$ x (NO_xRemoved/hr)$^{0.12}$ x BTF x RF
For Fuel Oil and Natural Gas-Fired Industrial Boilers:
BOP_{cost} = 213,000 x (Q_B/NPHR)$^{0.33}$ x (NO_xRemoved/hr)$^{0.12}$ x 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 days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1373	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0300	lb/MMBtu
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)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	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	^{o}F
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) =	$A \times 1{,}000 \times 0.0056 \times (CoalF \times HRF)^{0.43}$ = 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	Plant Elevation	4455	Feet above sea level
Number of days the boiler operates (t_{plant})	365	days	1.775	NSR	
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.1373	lb/MMBtu	25%	Control Efficiency	
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.1029	lb/MMBtu			
Estimated Normalized Stoichiometric Ratio (NSR)	0.50				

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
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

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*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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR)$ = (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) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	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 1×10^6)/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

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

What type of fuel does the unit burn? Natural Gas

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 days the boiler operates (t_{plant})	365	days
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1373	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0300	lb/MMBtu
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)	UNK	Cubic feet
Flue gas flow rate ($Q_{fluegas}$) (Enter "UNK" if value is not known)	UNK	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})	484	ft^3/min-MMBtu/hour

*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
Annual Interest Rate (i)	6.95	Percent		
Reagent ($Cost_{reag}$)	0.950	$/gallon for 19% ammonia		
Electricity ($Cost_{elect}$)	0.0754	$/kWh		
Catalyst cost ($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*		

CEPCI = Chemical Engineering Plant Cost Index Mar-23

* verification required -Jmin

* verification required - Jmin

* 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.

<u>Other Operating Costs Impacts</u>

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

<u>Turbine Design Parameters</u>			
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
<u>SCR Assumptions:</u>			
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)
<u>Calculated values and adjustment factors for estimating Catalyst Volume</u>			
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)

<u>SCR Calculated Catalyst Volume (entire reactor) EAP CCM Methodology 1</u>			
Vol_{cat}	Catalyst Volume	3661.90	ft3 (calculated)
		Catalyst Volmue (ft3)	$= 2.81 \times Q_B \times Ef_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times (T_{adj}/N_{scr})$
<u>Calc. Annual Catalyst Costs</u> (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 Regulation Incorporated by Reference

Appendix C.1 – R138-24 Regional Haze Regulation Pertaining to NV Energy's North Valmy and Tracy Generating Stations

Appendix C.2 – Secretary of State Stamp for LCB File No. R138-24 with Effective Date

Appendix C.3 – Evidence of Public Notice for the November 19, 2024, Sate Environmental Commission Hearing

Appendix C.4 – Evidence of Public Notice for the October 15, 2024, Regulatory Workshop

Appendix C.1 – R138-24 Regional Haze Regulation Pertaining to NV Energy's North Valmy and Tracy Generating Stations

Provisions provided in the following Nevada permanent regulation R138-24 for the Valmy and Tracy Generating Stations 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. Nevada's Division of Environmental Protection is submitting all of Section 1 of R138-24 and only Provision 13 of Section 2 of R138-24, which incorporates 40 CFR Part 75 by reference, for SIP approval.

APPROVED REGULATION OF THE

STATE ENVIRONMENTAL COMMISSION

LCB File No. R138-24

Filed December 19, 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 into consideration those federal requirements for establishing reasonable progress goals 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 limits 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 toward achieving natural visibility conditions, 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 the requirements of 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 the requirements of 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 C.2 – Secretary of State Stamp for LCB File No. R138-24 with Effective Date

Secretary of State Filing Data	For Filing Administrative Regulations	For Emergency Regulations Only
FILED.NV.SOS 2024 DEC 19 PM12:57	R138-24	Effective Date Expiration Date Governor's Signature

State Environmental Commission

Classification: Proposed [ ] Adopted By Agency [ ] Temporary [] Emergency [ ] Permanent **[XX]**

R138-24: This permanent regulation revises NAC 445B. The State Environmental Commission adopted permanent regulation R138-24P, which addresses Nevada's Air program. This regulation establishes the emission limits and control measures required at the Valmy Units and Tracy Unit 4 Pinion Pine to meet Regional Haze reasonable progress requirements instead of closure.

Authority citation other than 233B:
§§ 1 and 2, NRS 445B.210.

Notice date: October 16, 2024
Hearing date: November 19, 2024

Appendix C.3 – Evidence of Public Notice for the November 19, 2024, State Environmental Commission Hearing

- Permanent Regulation - Informational Statement
- State Environmental Hearing Notice of Regulatory Hearing
- State Environmental Commission Hearing Agenda

Permanent Regulation - Informational Statement

A Permanent Regulation Related to Environmental Programs

Legislative Review of Adopted Permanent Regulations as Required
by Administrative Procedures Act, NRS 233B.066

State Environmental Commission
Permanent No: R138-24P

The Nevada State Environmental Commission (SEC) offers the following informational statement in compliance with Nevada Revised Statute (NRS) 233B.066.

1. Need for Regulation

On March 1, 2024, the Public Utility Commission of Nevada approved NV Energy's 5th amendment to its 2021 Integrated Resource Plan. This amendment removed the planned closure of NV Energy's Valmy Generating Station Units 1 and 2 and Tracy Generating Station Unit 4 Piñon Pine. The Closure of these units was incorporated into Nevada's Regional Haze State Implementation Plan 2022 Revision. This regulation will establish the emission limits and control measures required at the Valmy Units and Tracy Unit 4 Piñon Pine to meet Regional Haze reasonable progress requirements instead of closure.

2. A description of how public comment was solicited, a summary of public response and an explanation of how other interested persons may obtain a copy of the summary.

The Division held a hybrid (in-person and virtual) public workshop for R138-24P on October 15, 2024. The public was invited to participate in person in the Bryan Building at 901 South Stewart Street in Carson City, Nevada, as well as at the NDEP offices at 375 East Warm Springs Road in Las Vegas, Nevada. The workshop was held to present the substance of, and receive public comment on, the proposed regulation. Twelve members of the public and regulated industry attended the workshop either in person or virtually. The proposed regulations were also distributed to the Bureau of Air Quality Planning's email distribution list.

The Legislative Counsel Bureau published its draft, R138-24P, in the Nevada Register on September 17, 2024. The Division accepted written comments on R138-24I and R138-24P for 30 days ending on October 11, 2024. The Division did not receive any verbal questions concerning R138-24I and/or R138-24P during the public workshop. A summary of the workshop, including any public comment and bureau response, is included on the NDEP website as well as the SEC website.

The SEC held a hybrid regulatory hearing on November 19, 2024, to consider possible action on R138-24P. The SEC posted its public notice, which included a link[1] and instructions to access R138-24P and pertinent documents and information supporting the regulation, for the regulatory meeting at the State Library in Carson City, at Division offices located in both Carson City and Las Vegas, at all county libraries throughout the state, and to the SEC email distribution list. The SEC also posted the public notice at the Division of Minerals in Carson City, at the Department of Agriculture, on the LCB website, on the Division of Administration website, and on the SEC website.

The SEC also published the public notice in the Las Vegas Review Journal and Reno Gazette Journal newspapers once per week for three consecutive weeks prior to the SEC regulatory meeting.

3. The number of persons who attended the SEC Regulatory Hearing:

(a) Attended November 19, 2024, hearing: 37 (approximately)
(b) Testified on this Petition at the hearing: 2

1. Andrew Tucker, on behalf of the Nevada Division of Environmental Protection
   901 South Stewart Street, Suite 4001
   Carson City, Nevada 89701
   (775) 687-9340
   atucker@ndep.nv.gov

2. Ken McIntyre, on behalf of the Nevada Division of Environmental Protection
   901 South Stewart Street, Suite 4001
   Carson City, Nevada 89701
   (775) 687-9493
   kmcintyre@ndep.nv.gov

(c) Submitted to the agency written comments: one

1. Mathew Johns, Vice President, Environmental Services and Land Management, NV Energy

4. A description of how comment was solicited from affected businesses, a summary of their response, and an explanation of how other interested persons may obtain a copy of the summary.

Comments were solicited from affected businesses through one public workshop and at the November 19, 2024, SEC hearing as noted in number 2 above.

[1] https://sec.nv.gov/meetings/sec-meeting-november-19-2024

5. If the regulation was adopted without changing any part of the proposed regulation, a summary of the reasons for adopting the regulation without change.

The Commissioners unanimously adopted R138-24P without change because the public and the SEC were satisfied with the proposed regulation.

6. The estimated economic effect of the adopted regulation on the business which it is to regulate and on the public.

<u>Regulated Business/Industry:</u> There are no economic impacts to businesses associated with this action in the short- or long-term.

<u>Public:</u> There are no adverse or economic impacts on the public associated with this action in the short- or long-term.

7. The estimated cost to the agency for enforcement of the adopted regulation.

<u>Enforcing Agency.</u> The regulation does not impose functions on the agency that is not already required by the Clean Air Act (CAA), so no additional costs beyond what the agency would normally incur are expected.

8. A description of any regulations of other state or government agencies which the proposed regulation overlaps or duplicates and a statement explaining why the duplication or overlapping is necessary. If the regulation overlaps or duplicates a federal regulation, the name of the regulating federal agency.

The regulation is required for NDEP's compliance with the federal Regional Haze Rule and the CAA. The stringency of the requirements is consistent with the requirements of federal regulations and the CAA as well as being consistent with comparable regulations at the local level.

9. If the regulation includes provisions which are more stringent than a federal regulation, which regulates the same activity, a summary of such provisions.

The proposed amendments in R138-24P do not include requirements that are more stringent than federal regulations.

10. If the regulation provides a new fee or increases an existing fee, the total annual amount the agency expects to collect and the manner in which the money will be used.

R138-24P does not provide for any new fees or increases to existing fees.

State of Nevada
Dept. of Conservation & Natural Resources
State Environmental Commission
901 South Stewart Street, Suite 4001 -- Carson City, Nevada 89701-5249

Notice of Regulatory Hearing
Adoption of Regulations and Other Matters Before the State Environmental Commission

The State Environmental Commission (SEC) will hold a meeting on Tuesday, November 19, 2024, at 9:00 am. The meeting will be held in the Bonnie B. Bryan Room, on the first floor of the Bryan Building, at 901 South Stewart Street in Carson City, Nevada. There is also the option to participate virtually using the link below.

Join the meeting https://teams.microsoft.com/l/meetup-join/19%3ameeting_MmUzYjM5ZDItMTU3MC00NDNjLWFiMzAtYTlmODQyNWM5YWFm%40thread.v2/0?context=%7b%22Tid%22%3a%22e4a340e6-b89e-4e68-8eaa-1544d2703980%22%2c%22Oid%22%3a%22f7cf1a57-aa9a-4aa8-ab6b-9414ab15f56e%22%7d

Meeting ID: 221 886 800 244
Passcode: ZgKrzJ

Click to call from Mobile (audio only)
+1 775-321-6111,,646342902#

Call in by Phone (audio only)
United States: +1 775-321-6111
Meeting extension: 646 342 902#

The meeting will also be streamed to the Red Rock Conference room at the Las Vegas Nevada Division of Environmental Protection (NDEP) offices, located at 375 East Warm Springs Road. The purpose of this meeting is to receive comments from all interested persons regarding the information listed on this notice and the meeting agenda. The following information is provided pursuant to the requirements of Nevada Revised Statutes (NRS) 233B.0603.

Permanent Regulation R133-24: Bureau of Safe Drinking Water - Regulatory Clean-up in Response to the Governor's Executive Order EO2023-003

R133-24 is proposing to amend various sections of Nevada Administrative Code (NAC) 445A to streamline, clarify, and improve the regulations to provide for the general welfare of the State without unnecessarily inhibiting economic growth.

The proposed changes are not expected have any economic impact on the public, the regulated community, or the Division.

Permanent Regulation R138-24: Bureau of Air Quality Planning - Compliance with Federal Regional Haze Rule and Clean Air Act Requirements

R138-24 proposes to amend Chapter 445B of the NAC to establish the emission limits and control measures required at the Valmy Units and Tracy Unit 4 Pinion Pine to meet Regional Haze reasonable progress requirements instead of closure.

The proposed changes are not expected have any economic impact on the public, the regulated community, or the Division.

Permanent Regulation R144-24: Bureau of Air Quality Planning - Clean Trucks and Buses Incentive Program Requirements

On June 9, 2023, the governor of Nevada signed Assembly Bill (AB) 184, creating the Clean Trucks and Buses Incentive Program (Program), which provides voucher incentives for the purchase of zero emission medium- and heavy-duty vehicles, along with various requirements for the Program and other matters relating thereto.

In accordance with AB 184, this regulation includes additional requirements necessary for NDEP to effectively administer the Program.

The proposed changes are expected to have a largely positive economic impact on the businesses that voluntarily participate in the Program. Incentives are available to local governments, state agencies, and nonprofit organizations, which will have a positive economic impact on these entities. In addition, the adoption of zero emission vehicles will help improve air quality in those areas where the vehicles are driven.

Permanent Regulation R161-24: Bureau of Sustainable Materials Management - Hazardous Secondary Materials

NDEP is proposing to amend sections of Nevada Administrative Code (NAC) 444 to revise the definition of the Solid Waste Rule that was partially adopted in 2020. These amendments will provide regulatory clarification and framework promoting recycling of hazardous materials. The amendments also provide clear guidelines for the proper management of hazardous secondary materials.

The proposed changes are not expected to have any economic impact on the public, the regulated community, or the Division.

Additional Information: Persons wishing to comment on the proposed actions of the SEC may participate in the scheduled public hearing (virtually or by phone) or may address their comments, data, views, or arguments in written form to: State Environmental Commission, 901 South Stewart Street, Suite 4001, Carson City, Nevada 89701-5249. The SEC must receive written submissions at least five days before the scheduled public hearing.

If no person who is directly affected by the proposed action appears to request time to make an oral presentation, the SEC may proceed immediately to act upon any written submissions.

Members of the public can inspect copies of the regulations to be adopted at the State Library and Archives in Carson City (100 Stewart Street), and at the offices of the Division of Environmental Protection in Carson City and Las Vegas. The Carson City office is located at 901 South Stewart Street, Suite 4001 and the Las Vegas office is located at 375 East Warm Springs Road, Suite 200.

As required by the provisions of chapters 233B and 241 of Nevada Revised Statutes, the public notice for this hearing was posted at the following locations: the Bryan Building (901 South Stewart Street, Carson City, Nevada); the offices of the Division of Environmental Protection in Las Vegas (375 East Warm Springs Road, Suite 200), at the State Library and Archives building in Carson City (100 Stewart Street), the Nevada Division of Minerals, 400 W. King Street, Carson City, NV and the Department of Agriculture, 405 South 21st Street, Sparks, NV.

In addition, copies of this notice have been deposited electronically at major library branches in each county in Nevada as specified below. This notice and the text of the proposed regulations will also be available on the SEC's website at: https://sec.nv.gov/meetings/sec-meeting-november-19-2024. The proposed regulation denoted in this notice, is, or will be, posted on the Legislative Counsel Bureau's website at http://www.leg.state.nv.us/register/ and also the Department of Administration's website at https://notice.nv.gov/.

Members of the public who are disabled and require special accommodations or assistance at the meeting are requested to notify, in writing, the Nevada State Environmental Commission, in care of Sheryl Fontaine, Executive Secretary, 901 South Stewart Street, Suite 4001, Carson City, Nevada 89701-5249, facsimile (775) 687-5856, or by calling (775) 687-9374, no later than 5:00 p.m. on November 12, 2024.

This Notice was provided to or posted at the following Nevada county locations:

Carson City Library
900 North Roop Street
Carson City, Nevada 89701-3101

Churchill County Library
553 South Main Street
Fallon, Nevada 89406-3306

Las Vegas-Clark County Library District
Director of Marketing and Community Relations
7060 W. Windmill
Las Vegas, Nevada 89113

Douglas County Public Library
1625 Library Lane
Minden, Nevada 89423-0337

Elko County Library
720 Court Street
Elko, Nevada 89801-3397

Esmeralda County Library
Corner of Crook & 4th Street
P.O. Box 430
Goldfield, Nevada 89013-0430

Eureka County Library
10190 Monroe Street
Eureka, Nevada 89316

Humboldt County Library
85 East 5th Street
Winnemucca, Nevada 89445-3095

Battle Mountain Branch Library (Lander County)
625 South Broad Street
Battle Mountain, Nevada 89820

Lincoln County Library
63 Main Street
Pioche, Nevada 89043

Lyon County Library System
20 Nevin Way
Yerington, Nevada 89447-2399

Mineral County Public Library
P.O. Box 1390
Hawthorne, Nevada 89415

Pershing County Library
1125 Central Avenue
Lovelock, Nevada 89419

Storey County Library - Closed
Posted at Clerk's Office
Address below:

Storey County Treasurer and Clerk's Office
Drawer D
Virginia City, Nevada 89440

Tonopah Public Library (Nye County)
P.O. Box 449
Tonopah, Nevada 89049

Washoe County Library System
301 South Center Street
Reno, Nevada 89501-2102

White Pine County Library
950 Campton Street
Ely, Nevada 89301

State of Nevada
Dept. of Conservation & Natural Resources
State Environmental Commission SEC.nv.gov
901 South Stewart Street, Suite 4001, Carson City, Nevada 89701

Agenda
SEC Meeting

The State Environmental Commission (SEC) will hold a meeting on **Tuesday, November 19, 2024, at 9:00 am in Carson City**. The meeting will be held in the Bonnie B. Bryan conference room on the first floor of the Bryan Building, located at 901 South Stewart Street. Space is limited at this location; therefore, remote participation is encouraged. Additionally, the meeting will be video streamed to the Red Rock conference room at 375 East Warm Springs Road, Suite 200, in Las Vegas. The public may also participate and provide public comment, either virtually or telephonically, using the following link or dial-in number:

Join the meeting: https://teams.microsoft.com/l/meetup-join/19%3ameeting_MmUzYjM5ZDItMTU3MC00NDNjLWFiMzAtYTlmODQyNWM5YWFm%40thread.v2/0?context=%7b%22Tid%22%3a%22e4a340e6-b89e-4e68-8eaa-1544d2703980%22%2c%22Oid%22%3a%22f7cf1a57-aa9a-4aa8-ab6b-9414ab15f56e%22%7d

Meeting ID: 221 886 800 244
Passcode: ZgKrzJ

Click to call from Mobile (audio only)
+1 775-321-6111,,646342902#

Call in by Phone (audio only)
United States: +1 775-321-6111
Meeting extension: 646 342 902#

Please Note: This is a stacked agenda, and the following items may be taken out of order and/or combined for consideration. Items may also be removed from the agenda, or the SEC may delay discussion relating to an item on the agenda at any time. No public comment may be taken on a contested case or quasi-judicial proceeding prior to the commencement and conclusion of a contested case or a quasi-judicial proceeding that may affect the due process rights of an individual. See NRS 233B.126.

1) Call to Order, Roll Call, Establish Quorum (Discussion only)

2) **Public Comment (Discussion Only)**

Those wishing to make public comment that are participating remotely may do so by calling (775) 321-6111 and using meeting extension 646 342 902#, or by raising your hand through the TEAMS platform so the moderator may call on you.

Members of the public will be invited to speak before the SEC; however, no action may be taken on a matter during public comment until the matter itself has been included on an agenda as an item for possible action. Public comment may be limited to three minutes per person at the discretion of the chairperson. Additional comments may be submitted to the Commission for inclusion in the meeting minutes.

3) **Approval of September 5, 2024, Draft Meeting Minutes (For Discussion and Possible Action)**

Regulatory Petitions

4) **Permanent Regulation R133-24: Bureau of Safe Drinking Water – Regulatory Clean-up in Response to the Governor's Executive Order EO2023-003**

R133-24 is proposing to amend various sections of Nevada Administrative Code (NAC) 445A to streamline, clarify, and improve the regulations to provide for the general welfare of the State without unnecessarily inhibiting economic growth.

The proposed changes are not expected to have any economic impact on the public, the regulated community, or the Division.

5) **Permanent Regulation R138-24: Bureau of Air Quality Planning – Compliance with Federal Regional Haze Rule and Clean Air Act Requirements**

R138-24 proposes to amend Chapter 445B of the NAC to establish the emission limits and control measures required at the Valmy Units and Tracy Unit 4 Pinion Pine to meet Regional Haze reasonable progress requirements instead of closure.

The proposed changes are not expected to have any economic impact on the public, the regulated community, or the Division.

6) **Permanent Regulation R144-24: Bureau of Air Quality Planning – Clean Trucks and Buses Incentive Program Requirements**

On June 9, 2023, the governor of Nevada signed Assembly Bill (AB) 184, creating the Clean Trucks and Buses Incentive Program (Program), which provides voucher incentives for the purchase of zero emission medium- and heavy-duty vehicles, along with various requirements for the Program and other matters relating thereto.

In accordance with AB 184, this regulation includes additional requirements necessary for NDEP to effectively administer the Program.

The proposed changes are expected to have a largely positive economic impact on the businesses that voluntarily participate in the Program. Incentives are available to local governments, state agencies, and nonprofit organizations, which will have a positive economic impact on these entities. In addition, the adoption of zero emission vehicles will help improve air quality in those areas where the vehicles are driven.

7) **Permanent Regulation R161-24: Bureau of Sustainable Materials Management – Hazardous Secondary Materials**

NDEP is proposing to amend sections of Nevada Administrative Code (NAC) 444 to revise the definition of the Solid Waste Rule that was partially adopted in 2020. These amendments will provide regulatory clarification and framework promoting recycling of hazardous materials. The amendments also provide clear guidelines for the proper management of hazardous secondary materials.

The proposed changes are not expected to have any economic impact on the public, the regulated community, or the Division.

Penalty Assessments

8) **Reck Brothers – NOAV No. 2892 (For Possible Action)**

NDEP to provide an update on the penalty assessment and associated Supplemental Environmental Project from the December 5, 2023, SEC meeting.

Alleged failures to construct or operate a stationary source in accordance with any condition of an operating permit, in violation of Class II Air Quality Operating Permit AP1611-0835.

9) **Reck Brothers – NOAV No. 3139 (For Possible Action)**

Alleged failures to construct or operate a stationary source in accordance with any condition of an operating permit, in violation of Class II Air Quality Operating Permit AP1611-0835.03.

Recommendation: Approve the NDEP-recommended penalty for Reck Brothers in the amount of $21,024 for NOAV No. 3139 or take other action as appropriate.

10) **Administrator's Briefing to the Commission: (For Discussion Only)** Administrator Jennifer Carr will provide the Commission with general management updates.

11) **Public Comment:** Members of the public will be invited to speak before the SEC; however, no action may be taken on a matter during public comment until the matter itself has been included on an agenda as an item for possible action. Public comment may be limited to three minutes per person at the discretion of the chairperson.

12) **Adjournment**

Additional Information: Persons wishing to comment on the proposed actions of the State Environmental Commission may appear at the scheduled public hearing or may address their comments, data, views, or arguments in written form to: **State Environmental Commission, 901 South Stewart Street, Suite 4001, Carson City, Nevada 89701-5249**. The SEC must receive written submissions at least five days before the scheduled public hearing.

If no person who is directly affected by the proposed action appears to request time to make an oral presentation, the SEC may proceed immediately to act upon any written submissions.

Members of the public can inspect copies of any regulations to be adopted at the State Library and Archives in Carson City (**100 Stewart Street**), and at the offices of the Division of Environmental Protection in Carson City and Las Vegas. The Carson City office is located at **901 South Stewart Street, Suite 4001,** and the Las Vegas office at **375 East Warm Springs Road, Suite 200.**

As required by the provisions of chapters 233B and 241 of Nevada Revised Statutes, the public notice for this meeting was posted at the following locations: the Bryan Building (**901 South Stewart Street, Carson City, Nevada**); the offices of the Division of Environmental Protection in Las Vegas (**375 East Warm Springs Road, Suite 200**), the Nevada Division of Minerals, **400 W. King Street, Carson City, NV** and at the Nevada Department of Agriculture (**405 South 21st Street, Sparks, Nevada**).

In addition, copies of this notice have been deposited electronically at major library branches in each county in Nevada. This notice and the text of the proposed regulations are also available on the State Environmental Commission's website at: https://sec.nv.gov/meetings/sec-meeting-sept-5-2024.

Any proposed regulations denoted in this notice, including previous drafts, are or will be posted on the Legislative Counsel Bureau's website.

Members of the public who would like to inspect all supporting materials for this meeting or members of the public who are disabled and require special accommodations or assistance at the meeting are requested to notify, in writing, the Nevada State Environmental Commission, in care of Sheryl Fontaine, Executive

Secretary, **901 South Stewart Street, Suite 4001, Carson City, Nevada 89701-5249**, facsimile **(775) 687-5856**, or by calling **(775) 687-9374** no later than 5:00 p.m. on August 28, 2024.

Appendix C.4 – Evidence of Public Notice for the October 15, 2024, Regulatory Workshop

- Notice of Public Workshop
- Public Workshop Agenda
- Public Workshop Summary
- Proof of Publication
    - Nevada Division of Environmental Protection Website
    - Nevada Legislative Counsel Bureau Administrative Regulation Notices
    - Nevada Public Notice Website
    - Nevada Division of Environmental Protection AirInfo_Notices LISTSERV
    - Summary of Public Notice Distribution

Notice of Workshop to Solicit Comments on Proposed Amendments to Nevada Administrative Code Chapter 445B

The Nevada Division of Environmental Protection (NDEP) is proposing regulations that will amend Nevada Administrative Code (NAC) 445B. The following workshop has been scheduled to solicit comments from persons interested in the amendment, which is described below. The workshop agenda is on the reverse side of this announcement.

October 15th, 2024
10:00AM – 12:00 PM

Bonnie B. Bryan Boardroom **1st Floor** **901 S. Stewart Street** **Carson City, NV 89701**	**Red Rock Conference Room** **Suite 200** **375 East Warm Springs Road** **Las Vegas, NV 89119**

Virtual Meeting Information via Microsoft Teams
Join on your computer or mobile app: Click here to join the meeting
Call In (audio only): +1 (775) 321-6111, Conference ID: 138 187 538

If receiving this document as a hard copy, you can access the meeting information at https://ndep.nv.gov/posts and search for the BAQP Workshop Notice

Permanent Regulation P2024-08 (R138-24): The NDEP is proposing to amend Nevada Administrative Code (NAC) 445B by adding a new section that pertains to emission limits and control measures required for Nevada Energy's Valmy generating Units (1 & 2) and Tracy Generating Station Unit 4 Piñon Pine. This new section is needed to meet the federal Regional Haze Rule and Clean Air Act requirements. If adopted, this regulation will be sent to the U.S. Environmental Protection Agency for approval into the Nevada State Implementation Plan (SIP).

The proposed amendments and related materials are available on the NDEP website at: https://ndep.nv.gov/posts. A copy of materials relating to the proposed regulations may also be obtained at the workshop or from Ken McIntyre at NDEP, 901 S. Stewart Street, Suite 4001, Carson City, NV 89701; (775) 687-9493; or e-mail kmcintyre@ndep.nv.gov. Members of the public who are disabled and require special accommodations or assistance at the meeting are requested to notify Ken McIntyre no later than 3 working days before the workshop. This notice has been posted on the official State website, the Nevada Legislature website and the NDEP website, at the NDEP offices in Carson City and Las Vegas, at the State Library in Carson City and at County libraries throughout Nevada.

Public Workshop to Solicit Comments on Proposed Amendments to Nevada Administrative Code Chapters 445B

October 15th, 2024
10:00 AM – 12:00 PM

Bonnie B. Bryan Boardroom **1st Floor** **901 S. Stewart Street** **Carson City, NV 89701**	**Red Rock Conference Room** **Suite 200** **375 East Warm Springs Road** **Las Vegas, NV 89119**

Virtual Meeting Information via Microsoft Teams
Join on your computer or mobile app: Click here to join the meeting
Call In (audio only): +1 (775) 321-6111, Conference ID: 138 187 538

If receiving this document as a hard copy, you can access the meeting information at https://ndep.nv.gov/posts and search for the BAQP Workshop Notice

AGENDA
(No action items)

1. Welcome, introductions.

2. Review of agenda; regulation adoption timeline.

3. Presentation of proposed regulation P2024-08 (R138-24): Proposed amendments to NAC 445B.

4. Public comments and questions on proposed regulation P2024-08 (R138-24). *

5. Adjourn

* Public comment may be limited to five minutes per person at the discretion of the chairperson. The chair reserves the right to dispense with repetitive comments on a given topic.

The proposed amendments and related materials are available on the NDEP website at: https://ndep.nv.gov/posts. A copy of materials relating to the proposed regulations may also be obtained at the workshop or from Ken McIntyre at NDEP, 901 S. Stewart Street, Suite 4001, Carson City, NV 89701; (775) 687-9493; or e-mail kmcintyre@ndep.nv.gov. Members of the public who are disabled and require special accommodations or assistance at the meeting are requested to notify Ken McIntyre no later than 3 working days before the workshop. This notice has been posted on the official State website, the Nevada Legislature website and the NDEP website, at the NDEP offices in Carson City and Las Vegas, at the State Library in Carson City and at County libraries throughout Nevada.

NEVADA DIVISION OF ENVIRONMENTAL PROTECTION

Workshop to Solicit Comments on Proposed Amendment to NAC 445B: Air Controls

October 15, 2024
10:00 AM

Bonnie B. Bryan Boardroom 1st Floor 901 South Stewart Street Carson City, NV 89701	Warm Springs Conference Room Suite 200 375 East Warm Springs Road Las Vegas, NV 89119

The workshop was also held virtually and was publicly accessible by video conference and phone

MEETING NOTES

ATTENDEES:

Workshop Chair:
Ken McIntyre, Supervisor, BAQP

NDEP Staff:
Andrew Tucker, Chief, BAQP
Patricia Bobo, Environmental Scientist, BAQP
Katherine Hanson, Environmental Scientist, BAQP
Nicholas Schlafer, Environmental Scientist, BAQP

Public:

Carson City:
Chris Heintz, NV Energy

Las Vegas:
Brigid McHale, NV Energy

Virtual[1]:

Franklin E Giles, BLM
Emma Lintz, BAQP
Debra C Miller, NPS
Matt Mannens
Scott
Joshua Legrande, Universal Engineering Sciences
Heather Borgen, Switch
Chris Peterson, Comstock Inc.
Tori Supple
Alex, Fireflies.ai Notetaker

[1] Participants are listed using their online registration. Last name and/or affiliation may not have been provided.

CALL TO ORDER

Mr. McIntyre called the meeting to order at 10:01 AM, explained the purpose of the Public Workshop, and introduced the staff present. Mr. McIntyre explained that the names of attendees would be collected for the record and that the meeting was being recorded. Mr. McIntyre reviewed the workshop agenda. There were no questions or changes to the agenda. Mr. Schlafer explained that virtual attendees would be muted by the moderator and how they could signal to the moderator that they had a question or comment so they could be unmuted. Mr. Schlafer explained that a copy of the proposed regulation, and State Environmental Commission (SEC) Forms 1 and 4, could be found on the Nevada Division on Environmental Protection's (NDEP) website.

Mr. McIntyre explained how the regulation adoption process works. The regulation adoption timeline was explained, specifying that there would be a 30-day public comment period prior to the SEC hearing for each set of proposed amendments. Mr. McIntyre stated that unless there are substantive changes based on feedback from this workshop, permanent regulation R138-24 is expected to be heard before the November 19th SEC hearing. Any information about the hearing can be found on the SEC website. If the regulations are adopted by the SEC, they are submitted to the Legislative Commission. If the Legislative Commission approves the regulations, they are filed with the Secretary of State and become effective. Mr. McIntyre paused and asked if there were any questions about the regulation adoption process.

There being no questions, Mr. McIntyre moved on to present the petition.

R138-24 SUMMARY

NDEP is proposing to amend Nevada Administrative Code (NAC) 445B by adding a new section that pertains to emission limits and control measures required for Nevada Energy's Valmy Generating Station Units (1 & 2) and Tracy Generating Station Unit 4 Piñon Pine. This new section is needed to meet the federal Regional Haze Rule (RHR) and the Clean Air Act requirements. If adopted, this regulation will be sent to the U.S. Environmental Protection Agency (USEPA) for approval into the Nevada State Implementation Plan (SIP).

This regulation is being proposed as part of Nevada's Regional Haze State Implementation Plan for the second planning period. In 1999, the USEPA announced a major effort to improve air quality in national parks and wilderness areas. The Regional Haze Rule (RHR) calls for state and federal agencies to work together to improve visibility in 156 national parks and wilderness areas.

In Nevada, there is one designated Class I area, the Jarbidge Wilderness Area in the northeast corner of the State. Visibility and sources of impairment at each Class I area are reviewed as part of the RHR. The primary visibility impairing pollutants are NO_X, SO_2, PM_{10}, NH_3, VOC, and $PM_{2.5}$.

NDEP has coordinated with, and requested input from, the USEPA, National Park Service, U.S. Fish and Wildlife Service, the U.S. Forest Service, Bureau of Land Management, Local Governments, NV Energy, other facilities impacted by the RHR, conservation groups, and the public, through meetings like this one. The development of Nevada's Regional Haze SIP, along with other air pollution control plans managed by NDEP, reduces pollution that causes visibility impairment in the State of Nevada.

All states are required to submit periodic updates to their Regional Haze SIP for the second planning period. Nevada submitted its Regional Haze SIP for the second planning period in August of 2022. As part of this process NDEP worked with affected facilities on how they could reduce emissions and comply with the RHR.

NV Energy completed a four-factor analysis to determine how best to meet the requirements of the RHR. This analysis reviewed the cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance and the remaining useful life of the source. After completing the four-factor analysis NV Energy concluded that the closure of North Valmy Generating Station (units 1 & 2), and Tracy Generating Station Unit 4 Piñon Pine was the best way to reduce emissions at these facilities.

Tracy Generating Station is approximately 17 miles west of Reno on I-80 while North Valmy is approximately 38 miles west of Winnemucca on I-80 as can be seen on this map. Jarbidge wilderness area can be found north of Elko just below the Idaho border.

NV Energy notified NDEP of plans to amend its Integrated Resource Plan (IRP) July 13, 2023. These new plans included the cancelation of closure for North Valmy and Tracy Unit 4 Piñon Pine, conversion of North Valmy to natural gas firing, and included funding to pursue modifications and appropriate emissions controls at these units. Nevada's 2022 Regional Haze SIP was partially withdrawn on July 27, 2023, to further evaluate the new conditions at North Valmy and Tracy Generating Stations.

NV Energy testified to Nevada's Public Utilities Commission that 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. After a public hearing, NV Energy's IRP was approved by the Public Utilities Commission on March 1, 2024.

A four-factor analysis was updated for both units at the Valmy Generating Station to include the fuel conversion to natural gas. SO_2 emissions were found to be effectively controlled by conversion to natural gas. The installation and operating costs of selective non-catalytic reduction (SNCR) and flue gas re-circulation (FGR) were below the $10,000 per ton threshold set by NDEP and therefore cost effective. An emission rate of 0.1029 lb/million Btu (30-day rolling average) was set based on achievable limits at North Valmy with SNCR.

Selective catalytic reduction (SCR) was above the $10,000 cost per ton threshold but is being included in the regulation to provide flexibility with current and future national regulations that affect electricity generating units.

As part of North Valmy Generating Station's conversion to natural gas, low NO_X burners will be installed, along with either SNCR, FGR, or SCR for the control of NO_X. Since the controls at North Valmy Generating Station are dependent on the conversion of the facility to natural gas, a compliance date of June 1, 2027, is being set for completion of the conversion.

Controls will be installed and operating no later than 36 months after approval by the USEPA of Nevada's determination of reasonable progress towards achieving natural visibility conditions.

A four-factor analysis was updated for Tracy Unit 4 Piñon Pine to reflect the removal of closure. This analysis found that the installation and operating costs of SCR was below the $10,000 per ton threshold set by NDEP and therefore cost effective. A NO_X emission rate of 0.0151 lb/million Btu (30-day rolling average) was set based on achievable limits at North Valmy with SCR.

Pipeline quality, natural gas, and steam injection are currently used at Tracy Unit 4 Piñon Pine and have been included in this regulation since continued use will control SO2 and NOX emissions respectively. These controls have been determined necessary to achieve reasonable progress under the Regional Haze Rule.

Controls will be installed and operating no later than 36 months after approval by the USEPA of Nevada's determination of reasonable progress towards achieving natural visibility conditions.

The conversion to natural gas at Valmy and installation of controls at Valmy and Tracy Unit 4 Piñon Pine will result in combined emission reductions of 1,369 tpy NO_X, 2,309 tpy SO_2, and 16 tpy PM_{10}. The reductions in SO_2 are primarily achieved by the conversion to natural gas while the reductions in NO_X are driven by the installation of SCR and SNCR controls.

Monitoring, record keeping, and reporting requirements associated with this regulation include:

- Install, calibrate, maintain and operate a continuous monitoring system.
- Maintain a log of monitoring and recordkeeping.
- Annually submit a report in accordance with the reporting requirements of this chapter and Title 40 Part 75 of the Code of Federal Regulations (40 C.F.R. Part 75).

These requirements are currently incorporated into NV Energy's Title V operating permit for both Tracy and North Valmy.

As part of this regulation NDEP is proposing to amend NAC 445B.221 to adopt 40 C.F.R. Part 75 as part of this regulation, this process is known as adopt by reference.

Part 75 establishes requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program.

The adoption by reference of federal regulations allows NDEP to request delegated authority from the USEPA for the compliance and enforcement of air regulations.

The decision not to retire North Valmy and Tracy Unit 4 Piñon Pine results in a slight decline in modeled visibility at Jarbidge wilderness area during the most impaired days and no change in visibility during the clearest days.

This decrease in visibility is represented by a 0.001 deciview increase in the 2024 revised reasonable progress goal (RPG) from the 2022 RPG.

Nevada's modeled 2028 reasonable progress goal of 7.76 deciviews is below the 8.20 deciview value calculated by the uniform rate of progress glidepath (URP), for observations during the most impaired days (MID). This glidepath projects a value of 7.39 deciviews, during the most impaired days in 2064, which is the goal set by the regional haze rule to attain natural visibility conditions. At the bottom of the chart, you can see that the 2028 projection of 1.72 deciviews during the clearest days is well below the clearest days baseline of 2.56 deciviews.

In conclusion, the cancellation of closure of North Valmy and Tracy Unit 4 Piñon Pine from NV Energy's IRP was deemed necessary by Nevada's Public Utilities Commission March 1, 2024. The conversion to natural gas and emission controls listed in R138-24 will ensure North Valmy and Tracy Unit 4 Piñon Pine meet Nevada's reasonable progress goals outlined by the Regional Haze Rule. Nevada is on track to meet visibility goals by 2028 and natural conditions by 2064.

Mr. McIntyre paused and asked if there were any questions or comments on R138-24.

COMMENTS AND QUESTIONS

There were no questions or comments regarding R138-24.

CLOSING REMARKS AND ADJOURMENT

Mr. McIntyre asked if there were any other comments or questions, there being none, Mr. McIntyre thanked everyone for their time and participation in the public workshop and the meeting was adjourned at 10:20 AM.

NEVADA DIVISION OF
ENVIRONMENTAL
PROTECTION

STATE OF NEVADA
Department of Conservation & Natural Resources
Joe Lombardo, *Governor*
James A. Settelmeyer, *Director*
Jennifer L. Carr, *Administrator*

Public Notice

Memorandum

To: File

From: Shantell Davis, BAPC

Date: 9/26/2024

Re: Website Update – Public Notice

This memorandum is to serve as an official record demonstrating the publication of a public notice on the Nevada Division of Environmental Protection Website. A screenshot of the public notice webpage is attached. The publication details of the public notice is as follows:

Publication URL: https://ndep.nv.gov/posts/oct-2024-workshop-on-proposed-amendments-to-nac-445b

Date of Publication: 9/26/2024 **Time of Publication:** 1:34 PM

Beginning of Public Comment Period: 9/26/2024

End of Public Comment Period: 1/15/2025

Publication Expiration Date: 1/15/2025 **Time of Expiration:** 11:59 PM

Screenshot of Public Notice:

ndep.nv.gov/posts/oct-2024-workshop-on-proposed-amendments-to-nac-445b

NEVADA DIVISION OF
ENVIRONMENTAL
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Start Your Search

Oct. 2024 Workshop on Proposed Amendments to NAC 445B

September 26, 2024

The Nevada Division of Environmental Protection is proposing regulations, relating to the Regional Haze Rule, that will amend several sections and subsections of NAC 445B. A workshop has been scheduled to solicit comments from persons interested in the amendments.

The workshop will be held on October 15, 2024 from 10:00 am to 12:00 pm and will be located at the following locations:

Bonnie B. Bryan Boardroom 1st Floor 901 S. Stewart Street Carson City, NV 89701	Red Rock Conference Room Suite 200 375 East Warm Springs Road Las Vegas, NV 89119

See All News and Updates

You May Be Interested In...

Notice of Decision – BMRR – Columbus Salt Marsh Project

READ MORE

Notice of Proposed Action – BWPC – Orovada Wastewater Treatment Facility

READ MORE

Notice of Proposed Action – BMRR – Thomas Mine

READ MORE

Administrative Regulation Notices

Meetings and Workshops

NRS 233B.0601 (/NRS/NRS-233B.html#NRS233BSec0601) (Added by AB 252 of the 77th (2013) Session)

Add a New Notice (/App/Notice/A/Submit)

Today is Friday, September 27, 2024

09/27/2024 9:00AM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/NOI092724FINAL.09272024.570.pdf)
Division of Human Resource Management (http://hr.nv.gov)
Human Resources Commission Meeting
Nevada State Library and Archives Building, 100 N. Stewart Street, Room 110, Carson City, NV 89701 with videoconference to the Eureka Building, 7251 Amigo Street, Suite 120, Las Vegas, NV 89119

09/28/2024 8:30AM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/CGR522NoticeofWorkshop.09282024.277.pdf)
Nevada Department of Wildlife
Notice of Workshop
Clark County Government Center, 500 S. Grand Central Parkway, Las Vegas, NV 89155

09/30/2024 9:00AM
Meeting Notice
(http://www.leg.state.nv.us/App/Notice/Doc/SecondPublicWorkshopNoticeforNAC432BQRTPProgrammaticRegulations093024.09302024.428.pdf)
Department of Health and Human Services Division of Child and Family Serivices
(https://dcfs.nv.gov/Meetings/2024/2024MeetingsandAgendas/)
Second Public Workshop NAC 432B Qualified Residential Treatment Program Programmatic Regulations
https://dcfs.nv.gov/Meetings/2024/2024MeetingsandAgendas/

09/30/2024 11:00AM
Meeting Notice
(http://www.leg.state.nv.us/App/Notice/Doc/FirstPublicWorkshopNoticeforNAC424432432BProposedRevisionstoRegulations093024.09302024.22.pd
Department of Health and Human Services Division of Child and Family Serivices
(https://dcfs.nv.gov/Meetings/2024/2024MeetingsandAgendas/)
First Public Workshop Notice for NAC Chapters 424, 432, and 432B Regulations
https://dcfs.nv.gov/Meetings/2024/2024MeetingsandAgendas/

09/30/2024 1:00PM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/DETRUITaxRateNAC612.270SmallBusinessWorkshop.09302024.247.pdf)
Department of Employment Training and Rehabilitation (https://detr.nv.gov/)
Small Business Impact Workshop Public Hearing
State Administrative Office - Auditorium 500 E Third St., Carson City, NV 89713

09/30/2024 1:00PM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/DETRUITaxRateNAC612.555SmallBusinessWorkshop.09302024.742.pdf)
Department of Employment Training and Rehabilitation (https://detr.nv.gov/)
Small Business Impact Workshop Public Hearing
State Administrative Office - Auditorium 500 E Third St., Carson City, NV 89713

09/30/2024 1:00PM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/DETRUITaxRateNAC612.555SmallBusinessWorkshop.09302024.780.pdf)
Department of Employment Training and Rehabilitation (https://detr.nv.gov/)
Small Business Impact Workshop Public Hearing
State Administrative Office - Auditorium 500 E Third St., Carson City, NV 89713

10/01/2024 1:00PM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/NAC_PH_10-01-24_Notice_of_Public_Hearing_and_SBI_Packet.10012024.477.pdf)
Division of Health Care Financing and Policy (https://dhcfp.nv.gov/)
NOTICE OF PUBLIC HEARING FOR THE ADOPTION OF REGULATIONS FOR THE ALL-PAYER CLAIMS DATABASE (APCD)
Microsoft Teams

10/01/2024 2:00PM
Meeting Notice
(http://www.leg.state.nv.us/App/Notice/Doc/Amended.Notice.Adoption.Hearing.LCB.File.R076.23.10.01.24_ADAcomplete.10012024.871.pdf)
Department of Business and Industry, Division of Industrial Relations (https://dir.nv.gov/Meetings/Meetings/)
Amended Notice of Intent to Act on Proposed Regulations and Hearing Agenda - LCB File No. R076-23

10/01/2024 2:00PM
Meeting Notice
(http://www.leg.state.nv.us/App/Notice/Doc/Notice.Adoption.Hearing.LCB.File.R076.23_October01.2024_completeADA.10012024.66.pdf)
Department of Business and Industry, Division of Industrial Relations (https://dir.nv.gov/Meetings/Meetings/)
Notice of Hearing for the Adoption of Regulations of the Division of Industrial Relations - LCB File No. R076-23

10/01/2024 2:00PM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/NoticeofWorkshopR135-24and191-24.10012024.237.pdf)
Nevada Department of Taxation (https://tax.nv.gov)
Regulation Workshop - R135-24 (RPTT) and R191-24 (Determination of Obsolescence)
4600 Keitzke Lane, Suite L235, Reno NV

10/02/2024 9:00AM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/Reck_Bros_Appeal_Agenda.10022024.96.pdf)
Nevada State Environmental Commission (https://sec.nv.gov/)
State Environmental Commission Appeal Hearing
Bryan Building, First Floor, Bonnie B. Bryan Conference Room - 901 South Stewart Street, Carson City, Nevada VIRTUAL PARTICIPATION through Teams - see SEC website for link

10/07/2024 9:00AM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/NoticeofIntenttoAdoptaRegulation-R036-24.10072024.960.pdf)
Nevada Department of Taxation (https://tax.nv.gov)
Regulation Adoption Hearing - R036-24
Legislative Counsel Bureau 401 South Carson Street, Room 2135 Carson City, NV 89701 and Nevada Legislature Office Building, Room 165 7230 Amigo Street Las Vegas, NV 89119

10/10/2024 10:00AM
Meeting Notice
(http://www.leg.state.nv.us/App/Notice/Doc/NoticeofIntenttoAdoptPublicMeetingandAgendaAB332NAC670B.10102024.918.pdf)
Financial Institutions Division (https://fid.nv.gov)
Notice of Intent to Act Upon a Regulation-Notice of Hearing of Adoption of Regulation- R120-23 AB332
Virtually Microsoft Teams and 3300 W. Sahara Avenue, Suite 250, Las Vegas, Nevada 89102

10/11/2024 8:00AM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/2024-10-11-Regulation_Workshop-Notice.10112024.249.pdf)
State of Nevada Board of Psychological Examiners (https://psyexam.nv.gov)
Notice of Workshop to Solicit Comments on Proposed Regulations
https://us06web.zoom.us/j/85650857079

NEW
10/15/2024 10:00AM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/R138-24_Workshop_Notice.10152024.667.pdf)
Nevada Division of Environmental Protection - Bureau of Air Quality Planning (https://ndep.nv.gov/)
Workshop on Proposed Amendments to Nevada Administrative Code 445B
901 S. Stewart St. Carson City, NV 89701 (Bonnie Conference Room 1st Floor)

10/17/2024 8:00AM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/Combinedpublichearings.10172024.287.pdf)
Commission on Peace Officers Standards and Training (https://post.nv.gov/Meetings/Commission_Meetings/)
Public Comment Hearing
Southpoint Hotel/Casino 9777 S. Las Vegas Blvd., Napa Room A, Las Vegas, NV 89183

NEW
10/17/2024 9:00AM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/October2024AgendaWorkshop.10172024.664.pdf)
Nevada State Board of Pharmacy (https://bop.nv.gov/Board/BoardMtgs/)
Notice of Public Workshop
The meeting can be listened to or viewed live over Zoom remotely or at: Hilton Garden Inn 7830 S Las Vegas Boulevard, Las Vegas, NV Videoconference at Zoom: https://zoom.us/j/5886256671 Teleconference at 1(669) 900-6833 Meeting ID: 5886256671

10/17/2024 9:00AM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/R189-24PublicHearingNotice.10172024.724.pdf)
Nevada State Board of Pharmacy
Notice of Public Hearing
The meeting can be listened to or viewed live over Zoom remotely or at: Hilton Garden Inn 7830 S Las Vegas Boulevard, Las Vegas, NV Videoconference at Zoom: https://zoom.us/j/5886256671 Teleconference at 1(669) 900-6833 Meeting ID: 5886256671

10/21/2024 9:30AM
Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/NDF_R154-24_Packet.10212024.193.pdf)
Nevada Division of Forestry (https://forestry.nv.gov/happening-now)
Nevada Division of Forestry Regulation Adoption Hearing

901 S. Stewart Street, Carson City, NV 89701

10/22/2024 1:00PM

Meeting Notice
(http://www.leg.state.nv.us/App/Notice/Doc/Notice.Adoption.Hearing.10.22.24.LCB.File.No.R131.24_ADAcomplete.10222024.931.pdf)
Department of Business and Industry, Division of Industrial Relations (https://dir.nv.gov/Meetings/Meetings/)
Notice of Intent to Act on Proposed Permanent Regulations and Hearing Agenda - LCB File No. R131-24

10/24/2024 10:00AM

Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/NGCNoticeLCBFileR06324P.10242024.481.pdf)
Nevada Gaming Commission (https://gaming.nv.gov/)
Notice of Intent to Act Upon A Regulation - LCB File No. R063-24P
7230 Amigo Street Las Vegas, Nevada 89119

NEW

11/19/2024 12:00PM

Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/R117_24_Hearing_Agenda.11192024.751.pdf)
Nevada State Board of Medical Examiners (https://medboard.nv.gov/)
R117-24 Regulation Hearing
325 E. Warm Springs Road, Suite 225, Las Vegas, Nevada 89119 Teleconferenced to 9600 Gateway Drive, Reno, Nevada 89521

Nevada Public Notice Website

Government

State

City

County

K-12

Higher Education

Special Districts

Entity

Department of Corrections

Department of Education

Department of Employment Training and Rehabilitation

Department of Health and Human Services

Department of Indigent Defense Services

Department of Motor Vehicles

Public Body

Division of Water Resources

Results for Division of Environmental Protection

Results are limited to the last 7 days and for all dates in the future.

Notice	Date Posted	Event Date	Time	Status	Type
Workshop on Proposed Amendment to Nevada Administrative Code 445B (https://ndep.nv.gov/posts/sept-2024-workshop-on-proposed-amendments-to-nac-445b)	9/4/2024	9/23/2024	2:00 PM	Scheduled	Workshop
Workshop for Proposed Regulation Revisions to NAC 445A (https://ndep.nv.gov/posts/sept-2024-workshop-on-proposed-amendments-to-nac-445a)	9/11/2024	9/26/2024	9:00 AM	Scheduled	Workshop
Workshop on Proposed Amendments to Nevada Administrative Code 445B (https://ndep.nv.gov/posts/oct-2024-workshop-on-proposed-amendments-to-nac-445b)	9/27/2024	10/15/2024	10:00 AM	Scheduled	Workshop

Today's Meetings

08:30 AM	Nevada Board of Wildlife Commissioners (https://www.ndow.org/events/september-2024-co
08:30 AM	Beacon Academy of Nevada (https://www.banv.org/Board%20Meetings/2017-18%20Agendas//September%202024%20Agenda.pdf)

09:00 Graduate & Professional Student Association (http://UNLV.edu/gpsa/agendas)

Email Address, No Website | Link to Website

Public Notice Access

Public Bodies wishing to post public notices must first register (/Account/Register) for an account. *It is recommended to use your government issued email address.*

Register (/Account/Register)

Next Steps after you register

Send an email to publicnotice@admin.nv.gov (mailto:publicnotice@admin.nv.gov) with the following information:

1. Your name and email address.
2. The type of Government (i.e. State, City, County, K-12, Higher Education, Special Districts).
3. The area or “Entity” your Government type represents. For example, if your Government type is County, tell us which County i.e. Churchill, Clark, Douglas, etc.
4. The name of the Public Body (aka Committee/Council/Board) you will be posting for? Please list all of the Public Bodies you will be responsible to post notices for.
5. After you send the email with this information, you will receive an email or phone call back from the Department of Administration’s Director’s Office to confirm your account has been successfully enrolled. If you have questions, please email publicnotice@admin.nv.gov (mailto:publicnotice@admin.nv.gov).

From:	Nicholas Schlafer
To:	airinfo_notices@listserv.state.nv.us
Cc:	Ken McIntyre; Patricia Bobo; Katherine Hansen
Subject:	Notice of Public Workshop
Date:	Friday, September 27, 2024 8:28:00 AM
Attachments:	R138-24_Workshop_Notice.pdf

Please find attached, for your information, a workshop notice, and agenda with information on how to access related materials. The Nevada Division of Environmental Protection (NDEP) is proposing regulations that will repeal and amend several sections and subsections of NAC 445B. Therefore, the NDEP is conducting this workshop to solicit comments on the proposed amendments.

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
775-687-9354

NEVADA DIVISION OF ENVIRONMENTAL PROTECTION

Nevada Department of CONSERVATION & NATURAL RESOURCES

Connect with us:

From:	LISTSERV.STATE.NV.US LISTSERV Server (17.0)
To:	Nicholas Schlafer
Subject:	Your message dated Fri, 27 Sep 2024 15:28:05 +0000 with...
Date:	Friday, September 27, 2024 8:43:35 AM

Your message dated Fri, 27 Sep 2024 15:28:05 +0000 with subject "Notice of Public Workshop" has been successfully distributed to the AIRINFO_NOTICES list (226 recipients).

Summary of Public Notice Distribution for the 10/15/24 Public Workshop (in preparation for the 11/19/24 SEC Hearing) sent out 9/27/24; grand total of recipients is 975.

Mailing List:	Number of Recipients:
• **General List**	3
→ NGO-1	
→ Public-1	
→ Libraries-1	
• **County Commissioners**	18

Listservs:

• **Air Info**	226
• **Air Consultants**	18
• **Class I/II Permittees**	469

Email List:

• **Environmental Organizations**	14
• **General List**	34
→ Industry-14	
→ Federal-3	
→ EPA-7	
→ DCNR-3	
→ State-4	
→ Local-3	
• **Libraries**	23
• **Tribal Organizations**	23
• **Regional Planning Agencies**	5
• **Legislators**	59
• **Newspapers**	12
• **NDEP Air Groups**	67
• **Las Vegas DEP**	2
• **NV Energy**	2

Grand Total: 975

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

Site	Year	bSO4	bNO3	bOMC	bEC	bSoil	bCM	bSs	bRay	calculated from b's b_other	b_total	dv	from TSS dv	dvTSS/dvCalc	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

Site	Year	bSO4	bNO3	bOMC	bEC	bSoil	bCM	bSs	bRay	calculated from b's b_other	b_total		from TSS dv	dvTSS/dvCalc	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					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	dv corr for 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.5 - Evidence of Invitation to In-Person Meeting

Appendix E.6 - NDEP Responsiveness Summary

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

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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.

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[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.

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[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			
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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	Plant Elevation: 4455 Feet above sea level (NVE 4FA)
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				

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} x 7.4805)/Reagent Density =	97.9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 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) x ((C_{stored}/C_{inj}) - 1) =	82	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	1.17	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/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

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**	Enter USGS commodity price & yr here.
Commodity Year:	2023		Enter USGS commodity cost year here.
Select NH3/Urea Type:	19% Aqueous		

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} x Q_B x NSR x MW_R)/(MW_{NOx} x 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} x 7.4805)/Reagent Density =	110.6	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 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 x NOx_{in} x NSR x 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 x $m_{reagent}$ x ((1/C_{inj})-1) =	1.32	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 ($SNCR_{cost}$) =	$2,831,849	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
$y = 22.554x + 16.725$

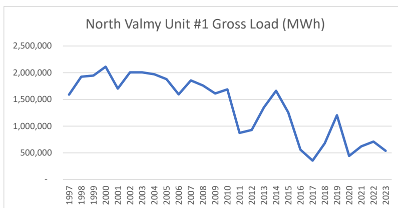
If x =	0.136	
y =	19.3	%
xout =	0.11	

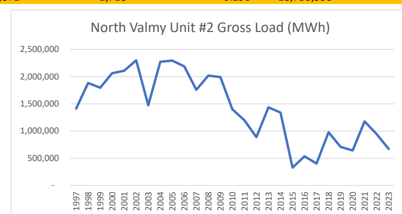
State	Facility Name	Facility ID	Unit ID	Year	Program Code	County	Source Category	Latitude	Longitude	Owner/Operator	Unit Type	Primary Fuel Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Commercial Operation Date	Operating Status	Max Hourly HI Rate (mmBtu/hr)	Associated Generators & Nameplate Capacity (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	Jorth 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/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	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	0.105	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)**

State	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/mmBtu)	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	Pipeline 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 (selected)

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})	255 days	254.53	CAMPD 2021-2023
Number of days the boiler operates (t_{plant})	255 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 °F
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 =	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 ($Vol_{catalyst}$) =	$2.81 \times Q_B \times EF_{adj} \times Slipadj \times NOx_{adj} \times S_{adj} \times (T_{adj}/N_{scr})$	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}) =	$(Vol_{catalyst}/(R_{layer} \times A_{catalyst})) + 1$ (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 ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times EF \times SRF \times MW_R)/MW_{NOx}$ =	115	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/Csol$ =	607	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density	78	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24)$/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) =	$A \times 1{,}000 \times 0.0056 \times (CoalF \times HRF)^{0.43}$ = 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} =	$271,295	in 2023 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$193,137	in 2023 dollars
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

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
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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
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***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
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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.

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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

Is the SCR for a new boiler or retrofit of an existing boiler? Retrofit

What type of fuel does the unit burn? Natural Gas

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 SCR reactor chambers (n_{scr})	1
Number of days the boiler operates (t_{plant})	239	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.

Estimated operating life of the catalyst ($H_{catalyst}$)	24,000	hours			
Estimated SCR equipment life	30	Years*	Gas temperature at the SCR inlet (T)	650	^{o}F
			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.

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} =	$301,579	in 2023 dollars
Annual Catalyst Replacement Cost =	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	$218,210	in 2023 dollars
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

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

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

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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
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Nevada Department of CONSERVATION & NATURAL RESOURCES
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Appendix E.5 – Evidence of Invitation to In-Person Meeting

From:	Nicholas Schlafer on behalf of Air Resources, NPS
To:	pleasant.mcneel@usda.gov; Tim Allen (Tim_allen@fws.gov); Nicholas Schlafer; Giles, Franklin E; Peters, Melanie; Nguyen, Khoi (she/her/hers); Shepherd, Don; Withey, Charlotte (she/her/hers); bohning.scott@epa.gov; Chen, Eugene; Graham, AshleyR (she/her/hers); DCNR Conf Rm Toquima 4-NE (TEAMS)
Cc:	Salazer, Holly; Miller, Debra C; Stacy, Andrea; King, Kirsten L
Subject:	NV Regional Haze Supplement Consultation Call
Start:	Tuesday, June 4, 2024 1:00:00 PM
End:	Tuesday, June 4, 2024 2:30:00 PM
Location:	Microsoft Teams Meeting

Discussion of Nevada's Regional Haze revision.

-----Original Appointment-----
From: Air Resources, NPS <airresources@nps.gov>
Sent: Monday, May 6, 2024 3:03 PM
To: Air Resources, NPS; Nicholas Schlafer; Peters, Melanie; Shepherd, Don
Cc: Salazer, Holly; Miller, Debra C; Stacy, Andrea; King, Kirsten L
Subject: Placeholder: NPS/NV Regional Haze Supplement Consultation Call
When: Tuesday, June 4, 2024 2:00 PM-3:30 PM (UTC-07:00) Mountain Time (US & Canada).
Where: Microsoft Teams Meeting

Hi Nick,

The NPS Regional Haze team is looking forward to this opportunity to talk through our conclusions and recommendations on the draft supplement to the Nevada Regional Haze SIP for the second implementation period.

Best,

Melanie Peters

Microsoft Teams Need help? <https://aka.ms/JoinTeamsMeeting?omkt=en-US>

Join the meeting now <https://teams.microsoft.com/l/meetup-join/19%3ameeting_ZDc2OWU2MjctNDQ2ZS00YzYxLWI1NTgtNmEyZDJiNzliZTU3%40thread.v2/0?context=%7b%22Tid%22%3a%220693b5ba-4b18-4d7b-9341-f32f400a5494%22%2c%22Oid%22%3a%229075d7e4-d199-4aea-ac1e-ceeb0d09df8c%22%7d>

Meeting ID: 250 902 948 022

Passcode: ew6fiR

Dial-in by phone

+1 202-640-1187,,171784895# <tel:+12026401187,,171784895> United States, Washington DC

Find a local number <https://dialin.teams.microsoft.com/4c997179-2249-4e53-b877-e71d83c10c7a?id=171784895>

Phone conference ID: 171 784 895#

For organizers: Meeting options <https://teams.microsoft.com/meetingOptions/?organizerId=9075d7e4-d199-4aea-ac1e-ceeb0d09df8c&tenantId=0693b5ba-4b18-4d7b-9341-f32f400a5494&threadId=19_meeting_ZDc2OWU2MjctNDQ2ZS00YzYxLWI1NTgtNmEyZDJiNzliZTU3@thread.v2&messageId=0&language=en-US> | Reset dial-in PIN <https://dialin.teams.microsoft.com/usp/pstnconferencing>

From:	Nicholas Schlafer
To:	pleasant.mcneel@usda.gov; Tim Allen (Tim_allen@fws.gov); Giles, Franklin E
Cc:	Peters, Melanie; Ken McIntyre; Steven McNeece
Subject:	NV Regional Haze consultation
Date:	Monday, May 20, 2024 2:07:00 PM

Good Afternoon,

Nevada DEP is meeting with the National Park Service, June 4th 2-3:30 pm Mountain time, to discuss our Regional Haze revision. I have forwarded the invitation if you like to join us. If you would like to propose a different date, please let me know and we can set up another meeting. Also please let me know if you have any questions or initial comments regarding our Regional Haze SIP revision.

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
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Appendix E.6 – NDEP Responsiveness Summary

Appendix E.6 - NDEP Responsiveness Summary
Nevada Division of Environmental Protection Bureau of Air Quality Planning

Responsiveness Summary to Federal Land Manager Comments

On April 14, 2024, pursuant to 40 CFR 51.308(i)(2), NDEP provided the Federal Land Managers (FLMs) with a draft Regional Haze State Implementation Plan Revision for the Second Planning Period for a 60-day review. NDEP received formal comments from the National Park Service on June 5, 2024. The following responses are provided below to satisfy the requirements of 40 CFR 51.308(i)(3).

Tracy Generating Station

NPS Comment 1: 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).

Response: NDEP thanks the NPS for their review of the Nevada 2024 draft Regional Haze State Implementation Plan Revision for the Second Planning Period and appreciates their comments.

North Valmy Generating Station

NPS Comment 2:
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.

Response: NDEP thanks the NPS for their independent review of the cost effectiveness of SCR installation at North Valmy Generating Station. NDEP acknowledges the differences in the NPS calculations when compared to those found in NV energy's four-factor analysis. Most of these differences have a minor impact on the cost effectiveness of SCR with the notable exception of the estimated actual annual MWh output. While there have been variations in annual MWh output at North Valmy Generating Station since the 2016-2018 baseline, NDEP decided to retain the original baseline to maintain consistency with the baseline established in the SIP for the Regional Haze Round 2 Planning Period. NDEP requested NV Energy update its four-factor analysis to include the 2023 CEPCI value and requested clarification on its reagent cost. After reviewing NV Energy's responses to NDEP's request for additional information (Appendix F) and four-factor analysis (Appendix B) NDEP does not find that SCR's cost effectiveness meets the $10,000/ton threshold.

NPS Comment 3:

The NPS analysis used more-recent, post-pandemic higher utilization data to reflect anticipated future utilization after IPC departs.

Response: NDEP recognizes that there is variability in utilization data at North Valmy Generating Station due to the COVID-19 pandemic, natural gas distribution issues and the scheduled departure of IPC. NDEP further recognizes the differences in 2016-2018 utilization data used by NV Energy and the 2021-2023 average used by NPS for Unit #1 and the 2023 single year value used by NPS for Unit #2. NDEP requested additional information on future electric output projections from NV Energy. NV Energy responded with 3 different future electric output projections for North Valmy Generating Station (Appendix F) of which the model with the highest utilization did not vary greatly from the 2016-2018 baseline. NDEP has also reviewed NV Energy's Integrated Resource Plan 5th Amendment and verified that IPC is not planning to depart usage of North Valmy Generating Station. After reviewing the NPS detailed feedback (Appendix E) and NV Energy's responses NDEP has decided to retain the original 2016-2018 baseline for this revision in order to maintain consistency with the baseline established in the SIP for the Regional Haze Round Second Planning Period.

NPS Comment 4:

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.

Response: NDEP acknowledges this comment and respectfully disagrees. When conducting a four-factor analysis for the North Valmy Generating Station, NDEP developed baseline emissions and determined SNCR as cost effective for both units. EPA's Guidance and Clarification Memo also requires that states evaluate whether a unit's existing measures are necessary to make reasonable progress. That is, when states are relying on existing measures, the state must ensure that the source will continue to use those control measures, not continue to achieve the same level of utilization or annual emissions. Utilization varies, especially for electrical generating units. NDEP does not consider a unit's utilization as an existing control measure that should be included in Nevada's long-term strategy.

NPS Comment 5:

The NPS review used a higher Heat Input values than NVE.

Response: NDEP recognizes that there are differences in the 2016-2018 average heat input values at North Valmy Generating Station used by NV Energy and the 2021-2023 average used by NPS for Unit #1 and the 2023 single year value used by NPS for Unit #2. NDEP requested additional information on future electric output projections from NV Energy. NV Energy responded with 3 different future electric output projections for North Valmy Generating Station (Appendix F) of which the model with the highest utilization did not vary greatly from the 2016-2018 baseline. After reviewing the NPS detailed feedback (Appendix E) and NV Energy's responses NDEP has decided to retain the original baseline to maintain consistency with the baseline established in the SIP for the Regional Haze Round Second Planning Period.

NPS Comment 6:

The NPS review assumed that SCR could achieve a slightly lower emission rate based on 2023 CAMPD data.

Response: While NDEP recognizes that SCR could achieve a slightly lower emission rate based on 2023 CAMPD data. NDEP decided to retain the original baseline to maintain consistency with the baseline established in the SIP for the Regional Haze Round Second Planning Period.

NPS Comment 7:

The NPS review used the 2023 (instead of 2024) CEPCI (as advised by OAQPS)

Response: NDEP requested further information on the CEPCI value used by NV Energy in its four-factor analysis. NV Energy responded that an unfinalized 2023 value, available at the time the analysis was performed, was used for the four-factor analysis. NV Energy provided an updated cost estimate using the finalized 2023 CEPCI value (Appendix F, Response Letter 10). NDEP verified that the cost estimate for SCR is still above the $10,000/ton threshold and has updated the cost estimates in Section 2.3.

NPS Comment 8:

The NPS review used the 2023 cost of anhydrous ammonia reagent.

Response: NDEP requested further information on the anhydrous ammonia reagent used by NV Energy. NV Energy responded that it uses a 19% aqueous ammonia solution for process safety reasons with a current cost of $1.70 per gallon which is 79% higher than the $0.95 cost used in the four-factor analysis (Appendix F, Response Letter 10). While this cost may be higher than the 2023 cost of anhydrous ammonia reagent NDEP will accept variations to the reagent used and cost differences due to safety requirements.

Appendix F – NV Energy Response Letters

Appendix F.1 - NV Energy Response Letter 9

Appendix F.2 - NV Energy Response Letter 10

Appendix F.3 - NV Energy Response Letter 11

Appendix F.1 – 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

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

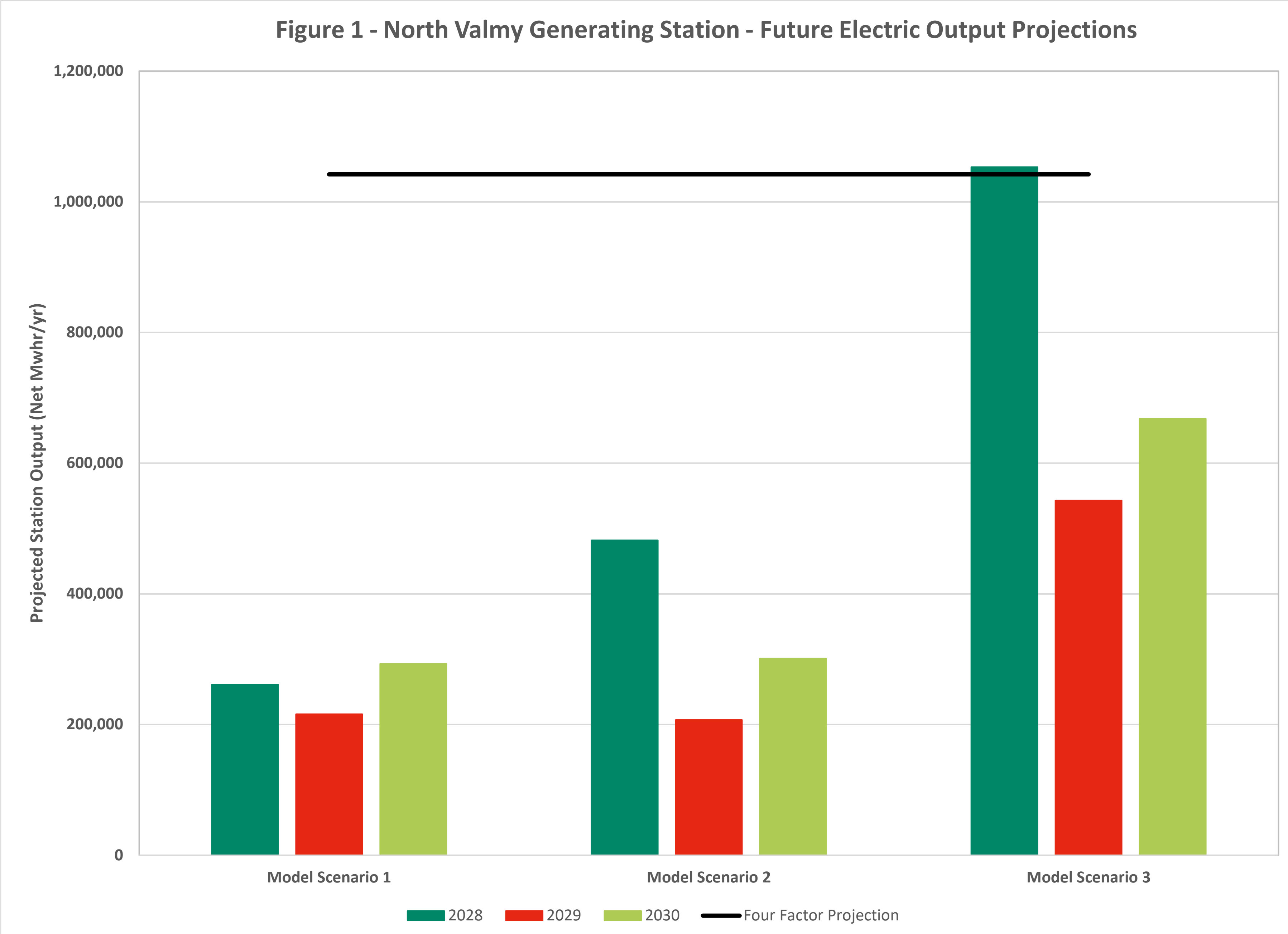
Figure 1 - North Valmy Generating Station - Future Electric Output Projections
Projected Station Output (Net Mwhr/yr)
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Model Scenario 1
Model Scenario 2
Model Scenario 3
2028
2029
2030
Four Factor Projection

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.

Appendix F.2 – NV Energy Response Letter 10

From:	Jelinek, Steve
To:	Nicholas Schlafer
Cc:	Ken McIntyre; Andrew Tucker; Heintz, Christopher (NV Energy); Johns, Mathew (NV Energy); McHale, Brigid (NV Energy)
Subject:	RE: [INTERNET] 4-Factor update - NV Energy North Valmy
Date:	Wednesday, January 8, 2025 12:37:27 PM

Hello Nick –

Per our telephone discussion on Monday please find below a summary of the estimated costs associated with installing Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR) to control nitrogen oxide (NOx) emissions from Units 1 and 2 at NV Energy's North Valmy Station after the units have been converted from coal to natural gas firing. Per our discussion, we understand that NDEP is interesting in knowing how much of an impact the use of a different Chemical Engineering Plant Cost Index (CEPCI) value would have on these cost estimates. We also understand that you have further questions about the reducing reagent cost component of the NOx control cost estimates.

You may recall that the SNCR and SCR cost estimates in the Updated Four Factor Assessment for North Valmy, submitted in March 2024, were based on the EPA's Control Cost Manual cost workbooks for these technologies, published in 2016. These workbooks utilize the CEPCI to adjust the capital cost estimates to reflect "current" dollars. For our cost estimates we used a CEPCI value of 824.5, which was the most up-to-date figure available at the time, for equipment to be constructed in 2024 and beyond.

We understand that in June 2024 NDEP received the results of SNCR and SCR cost assessments for North Valmy Units 1 and 2 conducted by the National Park Service (NPS). These assessments used a CEPCI value of 797.9, the "final" index value for equipment constructed in 2023, which was first published in the June 2024 edition of Chemical Engineering magazine. This index value was not available when the cost estimates for the Updated Four Factor Assessment were prepared. Additionally, we understand that the NPS used the 2023 CECPI value in their calculations because, as noted in a footnote to Table 3 of the NPS Consultation summary, EPA's Office of Air Quality Planning and Standards "recommended against using any 2024 CEPCI values yet."

The historical trend in CEPCI values indicates that the capital costs of both SNCR and SCR will likely be higher in the future than in 2024. As a result, NV Energy anticipates that the capital cost for these alternatives will exceed the estimates provided in the Updated Four Factor Assessment and in Table 3 of the NPS Consultation. Nonetheless, the following is a comparison of the cost estimates from Tables 4 and 5 of the Updated Four Factor Assessment with those estimates calculated using the 2023 CEPCI value.

	4 Factor Report	2023 CEPCI Value
CEPCI Value	824.5	797.9
Table 4 - NOx Control Options for North Valmy Unit 1		
SNCR		
Estimated Capital Cost	$7.89 million	$7.64 million
Annual Capital Recovery	$0.63 million/yr	$0.61 million/yr
Annual Operating Cost	$0.21 million/yr	$0.21 million/yr
Total Annual Cost	$0.84 million/yr	$0.82 million/yr
NOx Emission Rate with SNCR	258.5 tons/yr	
NOx Emission Reduction with SNCR	86.2 tons/yr	
Control Cost Effectiveness	$9,740/ton	$9,457/ton
SCR		
Estimated Capital Cost	$34.6 million	$33.5 million
Annual Capital Recovery	$2.77 million/yr	$2.68 million/yr
Annual Operating Cost	$0.76 million/yr	$0.76 million/yr
Total Annual Cost	$3.53 million/yr	$3.44 million/yr
NOx Emission Rate with SCR	75.3 tons/yr	
NOx Emission Reduction with SCR	269.3 tons/yr	
Control Cost Effectiveness	$13,122/ton	$12,769/ton
Table 5 - NOx Control Options for North Valmy Unit 2		
SNCR		
Estimated Capital Cost	$8.42 million	$8.15 million
Annual Capital Recovery	$0.68 million/yr	$0.65 million/yr
Annual Operating Cost	$0.24 million/yr	$0.24 million/yr
Total Annual Cost	$0.92 million/yr	$0.89 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	$7,791/ton
SCR		
Estimated Capital Cost	$37.1 million	$35.9 million
Annual Capital Recovery	$2.97 million/yr	$2.88 million/yr
Annual Operating Cost	$0.93 million/yr	$0.93 million/yr
Total Annual Cost	$3.90 million/yr	$3.80 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	$10,618/ton

Using the lower CEPCI value decreases the capital cost estimates for SNCR and SCR by a bit more than 3%, and there is thus a corresponding decrease in the capital recovery and total annual cost estimates for each option. Even considering the lower capital cost estimate, however, SCR is not a cost-effective control alternative for either unit at more than $10,000 per ton controlled.

You also asked about the ammonia reducing reagent cost used in our SNCR and SCR cost estimates.

NV Energy uses an aqueous ammonia solution with a maximum concentration of 19% NH_3 as the reducing agent in its newest SCR systems, primarily for process safety reasons. Our cost estimates assumed that this same solution would be used at North Valmy for NOx control with either SNCR or SCR. In March 2024, the delivered cost of ammonia solution at NV Energy's Tracy Station was $0.95 per gallon, which was the figure used in the Four Factor Assessment cost estimates. However, NV Energy's current cost for the 19% ammonia solution at Tracy Station is $1.70 per gallon, meaning the reducing agent costs in the Updated Four Factor Assessment are underestimated.

In comparison, the NPS cost calculations use a reducing reagent unit cost of $0.349 per gallon. However, the NPS does not provide additional details about the type of reducing reagent used in their calculations. According to a footnote in Table 3 of the NPS Consultation, the basis for this unit cost is "2023 USGS NH_3 price statistics." We were unable to locate this unit cost in the 2023 Mineral Commodity Summary for ammonia published by the United States Geological Survey; as a result, we cannot independently determine whether the NPS cost estimate is based on anhydrous ammonia or aqueous ammonia solution as the reducing agent.

NPS also developed their own cost estimates for SCR and SNCR in the early feedback they provided on the draft Four Factor Assessment Update that NV Energy submitted for your consideration in August 2023. In their feedback, NPS explicitly mentioned that their NOx control cost estimates were based on using a 29% aqueous ammonia solution as the reducing agent instead of the "more expensive" 19% ammonia solution. Therefore, it seems likely that NPS's most recent cost estimates are similarly based on the use of a 29% aqueous ammonia solution as the reducing agent.

As mentioned earlier, for process safety reasons NV Energy is using 19% aqueous ammonia solution as the reducing agent in its newest NOx control systems. Therefore, the unit cost of the 19% ammonia solution used in the cost estimates in the Updated Four Factor Assessment more accurately reflects the cost impact of implementing either SNCR or SCR on the North Valmy units than the unit cost used by the NPS does.

Should you have any further questions about the Four Factor NOx control cost estimates, please don't hesitate to contact me.

Best regards,

Steve Jelinek, PE
AECOM
250 Apollo Dr.
Chelmsford, MA 01824
(978) 905-2256 (office)

From: Nicholas Schlafer <n.schlafer@ndep.nv.gov>

Appendix F.3 – NV Energy Response Letter 11

NV Energy

April 24, 2025

Nicholas Schlafer
Environmental Scientist
Planning/Data Management Branch, Bureau of Air Quality Planning
Nevada Division of Environmental Protection
901 S. Stewart Street, Suite 4001
Carson City, NV 89701

RE: Request for Additional Information, Public Comments on Four-Factor Analysis for the NV Energy North Valmy and Tracy Generating Stations

Dear Nick,

NV Energy is pleased to provide you with the following information in response to the combined comments that the Nevada Division of Environmental Protection (NDEP) received from the National Parks Conservation Association (NPCA), Sierra Club and the Coalition to Protect America's National Parks (collectively, "Conservation Organizations") on the four-factor analysis performed on both North Valmy and Tracy Generating Stations in development of Nevada's 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). Since the comments from the Conservation Organizations were technical in nature, the following responses were primarily formulated by AECOM, who prepared the four-factor analysis.

North Valmy Generating Staton

Comment 3: Please verify the North Valmy NO_x baseline calculation (p. 12 comment letter). Instead of multiplying the 2016-2018 heat input average by 0.1373 lb/MMBtu it appears a projected 2028 capacity factor is used resulting in an approximately 5% higher NO_x baseline.

Response to Comment 3:
As stated in the Conservation Organizations' letter (PDF page 12), NVE estimates that NOx emissions in 2028 will be 344.6 tons per year for Valmy Unit 1 and 457.8 tons per year for Unit 2. However, the Conservation Organizations argue that these estimated emission rates exceed the values that would result if calculated using the average heat input rates from Units 1 and 2 during the baseline period.

As explained in Section 1.1.2 of the Updated Four Factor Analysis submitted in March 2024, the electric power output of the North Valmy Station during the 2016 – 2018 baseline period is considered representative of the projected future power output from the Station at the end of the second decadal review period (i.e., in 2028) following its conversion from coal firing to natural gas fuel firing. It is not appropriate, however, to project the 2028 emissions profile for the Station using the same heat input rates for Units 1 and 2 that occurred during the baseline period. When firing natural gas, Units 1 and 2 at North Valmy Station will have different boiler efficiencies than they did during the baseline period when firing coal.

The best available information on changes in boiler efficiency due to fuel conversion, as referenced in the Updated Four Factor Analysis, comes from a 2019 study by Burns & McDonnell. This study estimated that converting each unit from coal to natural gas firing would reduce boiler efficiency by 5.8%. Consequently, a higher heat input rate per unit would be required in 2028 to achieve the same electric power output as during the 2016–2018 baseline period. This projected efficiency reduction was incorporated into the 2028 NOx emissions profile estimates for these units.

NV Energy calculated projected actual NOx emissions for Valmy Units 1 and 2 when converted to natural gas using Low NOx burners (LNBs) and the following information:

- Heat Input: Unit 1, 2,554 MMBtu/hr; Unit 2, 3,058 MMBtu/hr.
- AP-42 Low NOx burner emission rate: 0.1373 lb/MMBtu (140 lb/10^6 scf ÷ 1020 Btu/scf)
- Capacity Factors: Unit 1, 22.4% (Updated Four Factor Analysis for the NV Energy North Valmy and Tracy Generating Stations, dated March 18, 2024, Appendix A, PDF pages 33 and 41) and Unit 2, 24.9% (Updated Four Factor Analysis for the NV Energy North Valmy and Tracy Generating Stations, dated March 18, 2024, Appendix A, PDF pages 48 and 56)
- Unit 1 calculation = 2,554 MMBtu/hr * 0.137 lb/MMBtu * 8760 hours/year * 0.224 capacity factor ÷2000 lb/ton = 344.6 tons.
- Unit 2 calculation = 3,058 MMBtu/hr * 0.137 lb/MMBtu * 8760 hours/year * 0.249 capacity factor ÷2,000 lb/ton = 457.8 tons.

The projected actual emissions result in approximately 5% increase in NOx emission over baseline emissions.

Comment 5: Please provide additional information on SCR and SNCR efficiency assumptions for North Valmy Generating Station (p. 14, 17, & 22 comment letter). Please document how the NOx inlet rate of 0.137 lb/MMBtu, SCR NOx outlet rate of 0.03 lb/MMBtu and SNCR NOx outlet rate of 0.1029 lb/MMBtu were derived.

Response to Comment 5:
As noted in Section 3.1 of the March 2024 Updated Four Factor Analysis, the projected NOx emission rate following the conversion of Units 1 and 2 to natural gas firing were derived assuming that new Low NOx natural gas-fired burners will be installed during the conversion. The emission rate of 0.137 lb NOx/MMBtu was calculated using the emission

factor associated with low NOx burners on large wall-fired boilers in Table 1.4-1 of US EPA's AP-42: Compilation of Emission Factors (140 lb/MMscf) and the nominal natural gas heating value utilized in AP-42 (1020 Btu/scf) described in footnote a of this table, as follows:

$$\left(\frac{140\ lb\ NOx}{MMscf}\right)\left(\frac{1{,}000{,}000\ Btu/MMBtu}{1{,}000{,}000\ scf/MMscf}\right)\left(\frac{scf}{1020\ Btu}\right) = 0.137\ lb/MMBtu$$

As explained in Section 4.1.2 of the Updated Four Factor Analysis, NV Energy estimated that the use of SNCR in conjunction with the conversion of the North Valmy units to natural gas firing would further reduce NOx emissions by 25%, based on information presented by the Arizona Department of Environmental Quality for conversion of Arizona Public Service's Cholla Generating Station. Accordingly, the SNCR outlet rate of 0.1029 lb/MMBtu was derived as follows:

$$\left(\frac{0.137\ lb}{MMBtu}\right)(1 - 0.25) = 0.1029\ lb/MMBtu$$

As also explained in Section 4.1.2 of the Updated Four factor Analysis, NV Energy estimated that the outlet rate of NOx associated with the use of SCR in conjunction with converting the North Valmy unit to natural gas firing would be 0.03 lb/MMBtu, which would represent a SCR NOx reduction efficiency of 78%, as follows:

$$\left(\frac{0.137\ lb}{MMBtu}\right)(1 - 0.78) = 0.03\ lb/MMBtu$$

According to Chapter 2, Section 4.2 of EPA's Control Cost Manual, this reduction efficiency is consistent with the midpoint of the rate of actual SCR control efficiencies achieved in practice (70 – 90%). Moreover, 0.03 lb/MMBtu was identified by EPA in 2023 as the basis for establishing future NOx allowances for natural gas-fired boilers equipped with SCR when promulgating the Good Neighbor Plan requirements (40 CFR 97.1010(a)(4)(iii)(B)(2)).

Comment 7: Please document the net plant heat input rate used for the cost estimate of SCR and SNCR (p.16 comment letter). A value of 10.765 MMBtu/MW was used for Unit 1, and 11.584 MMBtu/MW was used for Unit 2, instead of the control cost manual default value of 8.2 MMBtu/MW for natural gas.

Response to Comment 7:
As explained in the response to Comment 3, NV Energy commissioned an engineering study in 2019 to assess the feasibility of converting Units 1 and 2 at North Valmy from coal to natural gas firing. This study concluded that the boiler efficiency of each unit would decrease by 5.8% following conversion to natural gas firing. This efficiency loss is due to

the increase in the water content of the flue gas for natural gas firing compared to coal firing. The expected decrease in boiler efficiency means that the net heat rates for Units 1 and 2 when firing natural gas would be expected to increase in proportion to the efficiency decrease compared to the actual net heat rates that each unit exhibited during the baseline period when firing coal.

Based on data provided to the EPA Clean Air Markets Program, the actual net heat rates for Units 1 and 2 during 2016-2018 baseline period were 10.175 MMBtu/net MW and 10.949 MMBtu/net MW, respectively. Accordingly, the projected net plant heat rates used for the SCR and SNCR cost comparisons were calculated as follows:

Unit 1: 10.175 MMBtu/MW x 1.058 = 10.765 MMBtu/MW

Unit 2: 10.949 MMBtu/MW x 1.058 = 11.584 MMBtu/MW

Comment 9: Please provide additional documentation on the 0.50 value used for the normalized stoichiometric ratio (p. 17 comment letter).

Response to Comment 9:
As noted by the Conservation Organizations, EPA's Control Cost Manual Section 4, Chapter 1 on Selective Non Catalytic Reduction (SNCR) describes that "typical NSR values are between 0.5 and 3 moles of ammonia per mole of NOx" at the inlet to the SNCR system, and that "increasing the NSR has the effect of worsening the cost-effectiveness of SNCR" since the amount of reducing agent used (and thus the annual reagent cost) increases with increasing NSR. Accordingly, the cost effectiveness calculations prepared for the Updated Four Factor Analysis for North Valmy used the minimum "typical" NSR value recommended by EPA in the Control Cost Manual so as not to adversely bias the calculated cost effectiveness of this alternative.

Nonetheless, the results of the SNCR cost calculations presented in Appendix A of the Updated Four Factor Analysis demonstrate that using an NSR of 0.5 results in annual cost estimates that utilize approximately twice the molar ratio of reagent (ammonia) consumption to NOx removed, as follows:

$$Unit\ 1: \frac{\left(65\ lb\ NH3\ consumed/hr \Big/ 17.03 \frac{lb}{lbmol} NH3 \right)}{\left(87.63\ lb\ NOx\ removed/hr \Big/ 46.01 \frac{lb}{lbmol} NOx \right)} = \frac{2.004\ lbmol\ NH3}{lbmol\ NOx}$$

$$Unit\ 2: \frac{\left(78\ lb\ NH3\ consumed/hr \Big/ 17.03 \frac{lb}{lbmol} NH3\right)}{\left(104.94\ lb\ NOx\ removed/hr \Big/ 46.01 \frac{lb}{lbmol} NOx\right)} = \frac{2.008\ lbmol\ NH3}{lbmol\ NOx}$$

Comment 12: Please provide additional documentation on the \$0.075/kWh value used for the cost of electricity (p. 19 comment letter).

Response to Comment 12:
NV Energy used the figure of \$0.075/kWh for the cost of electricity in both the original Four Factor Analysis for North Valmy Station (submitted to NDEP in March 2020) and the Updated Four Factor Analysis (submitted in March 2024). The cost of electricity was previously discussed in the Response to a Third Follow-up Request for Additional Information, Regional Haze Four Factor Analyses, NV Energy Tracy (FIN 0029) and Valmy (FIN A0375) Generating Stations, dated April 16, 2021. In response to Tracy Question (b), this dollar per kWh value was intended to reflect both the unit cost of electricity and cost of capacity replacement. For consistency, no changes were made in the unit cost of electricity in the Updated Four Factor Analyses.

According to Section 4, Chapter 1 of EPA's Air Pollution Control Cost Manual, the default unit cost for electricity included in the Agency's Air Pollution Cost Estimation Spreadsheet for SNCR (\$0.0361/kWh) is the average total power plant operating cost for major U.S investor-owned fossil-fired steam electric utility plants in 2016. This value is from Table 8.4 of the U.S. Energy Information Administration's annual electric power summary. Since then, the EIA data indicates that plant operating costs have exhibited an average annual escalation rate of approximately 2.2% per year, and the most recent corresponding published electricity unit cost figure (for 2023) is \$0.0427/kWh.

According to the cost calculations in Appendix A of the Updated Four Factor Analysis for North Valmy, annual electricity costs make up only a small portion of the total annualized cost for SNCR (0.13% for Unit 1 and 0.15% for Unit 2), FGR (2.3% for Unit 1 and 2.9% for Unit 2), and SCR (5.8% for Unit 1 and 6.6% for Unit 2). Therefore, using either EPA's default unit electricity cost from 2016 or the most recent 2023 figure (\$0.0427/kWh) instead of the originally used value would have no material impact on the results. For either unit, SNCR and FGR would continue to be concluded to be cost effective NOx controls and SCR would continue to be concluded to be not cost effective.

Comment 13: Please provide additional documentation on the $1.66/MMBtu value used for the fuel cost (p. 20 comment letter).

Response to Comment 13:
The fuel cost value used in the SNCR and SCR cost calculations in the Updated Four Factor Analysis for North Valmy is the same cost figure as used in the original Four Factor Analysis submitted to NDEP in 2020. This value was chosen as a conservative coal cost value from the Energy Information Administration data on fuel cost delivered for electricity generation in the US Mountain Region during the baseline operating period for North Valmy (2016 – 2018). Note that the cost calculations presented in Appendix A of the Updated Four Factor report show that the additional fuel cost component represents an extremely small contribution to the total annual cost of this alternative (approximately 0.1% of the total annual cost estimates for SNCR for Units 1 and 2). Thus, the fuel cost component is essentially immaterial with respect to the cost effectiveness conclusions for SNCR.

As noted by the Conservation Organizations, the current EIA natural gas cost value ($3.36/MMBtu) is approximately two times higher than the value used in the SNCR cost calculations ($1.66/MMBtu). Thus, the cost calculations presented in the Updated Four Factor Analysis are conservative in that they provide cost effectiveness results that are lower than would have been obtained had the current natural gas cost value been used. Using the current EIA natural gas cost value, the cost effectiveness of SNCR for Unit 1 is estimated at $9,750/ton controlled (as compared to the $9,740/ton figure shown in the Updated Four Factor Analysis), while for Unit 2 the cost effectiveness of SNCR using the current EIA fuel cost value is estimated at $8,028/ton controlled (as compared to the $8,018 figure shown in the Updated Four Factor Analysis).

Comment 15: Please provide additional documentation for the inlet and outlet SCR NOx rates used (p. 22 comment letter).

Response to Comment 15:
As explained above in the response to Comment 5, the basis of the NOx emission rate at the SCR inlet is the NOx emission factor for large natural gas-fired boilers employing Low NOx burners from EPA's AP-42 Table 1.4-1. Also as explained above, the basis of the NOx emission rate at the SCR outlet is the emission rate that EPA used to establish future NOx allowances for natural gas-fired boilers equipped with SCR under the Good Neighbor Plan.

Comment 16: Please provide additional documentation on the 24,000 hour value used for the estimated operating life of the catalyst for SCR (p. 22 comment letter).

Response to Comment 16:
24,000 hours is the default estimated catalyst operating life that is pre-populated in the EPA's Control Cost Estimation Spreadsheet for Selective Catalytic Reduction. NV Energy has consistently used this value for the SCR cost estimates for the North Valmy Station for both the original and updated Four Factor Analysis.

Tracy Generating Staton

Comment 21: Please document the need for the 4.6 percent sales tax used in the cost effectiveness estimate (p. 29 comment letter). Does Nevada have a sales tax exemption for air pollution control equipment?

Response to Comment 21:
Sales tax on the equipment needed for an emissions control system is specifically called out in Section 2.6.4.1 of EPA's Control Cost Manual as an element of the estimated total capital expenditure for such systems. Accordingly, the capital cost to retrofit a Selective Catalytic Reduction (SCR) system on Unit 4 at Tracy Station was estimated using a sales tax factor equal to the state's base sales tax rate (4.6%), exclusive of any local sales taxes collected in Washoe County.

The Control Cost Manual acknowledges that sales taxes do not apply to emission control equipment in some locations. While NRS 361.077(1) does state that "a facility, device, or method for the control of air or water pollution" is exempt from taxation, this provision may not apply to the prospective SCR system proposed for Tracy Station's Unit 4. NV Energy has not consulted with Nevada tax professionals on this question, but NRS 361.077(2) indicates that the exemption only applies to equipment whose primary purpose is compliance with existing laws or standards. In this instance SCR represents a prospective alternative to improve visibility in nearby Class I areas rather than a system needed to comply with an existing emission standard.

Nonetheless, excluding the sales tax component from the total capital cost estimate for SCR would have only a marginal impact on the cost effectiveness of this alternative and would not change NV Energy's conclusion that retrofitting an SCR system on Unit 4 at Tracy Station represents reasonable further progress toward the goals of the Regional Haze Program.

Comment 22: Please document the need for the engineering, procurement, and construction contract surcharge in the cost effectiveness estimate (p. 29 comment letter). Is the use of this surcharge included in the EPA's Cost Control Manual's oversight methodology?

Response to Comment 22:
As shown in Table B-3 of Appendix B, the total capital expense associated with retrofitting an SCR system on Unit 4 at Tracy Station was estimated assuming that the retrofit project would be carried out on an EPC (engineer, procure, construct) contract basis, as NV Energy typically carries out equipment upgrades at its generating stations on this basis. The contractor fee employed in developing this estimate (15% of the total capital expense) is consistent with the value delineated in the document "Oil/Gas-fired SCR Cost Development Methodology" published in conjunction with EPA's Retrofit Cost Analyzer.

Section 2.6.4.2 of EPA's Control Cost Manual outlines key considerations for retrofitting new emission control systems on existing sources. It describes the two most common project execution methods: design-build and design-bid-build. The section also clarifies that "design-build," and "EPC" are used interchangeably. Additionally, Section 2.4.1 states that "contractor fees" are part of a project's direct installation costs. Therefore, including an EPC contractor fee in the total capital cost estimate for installing an SCR system on Unit 4 at Tracy Station aligns fully with the methodology described in EPA's Control Cost Manual. The Control Cost Manual does not, however, contain any mention of an "oversight methodology" for estimating emission control equipment costs, and NV Energy is not familiar with this term in the context of air pollution control cost estimates. Similarly, the 10th Circuit Court decision referenced by the Conservation Organizations on page 25 of their comments (Oklahoma v. EPA, 723 F.3d 1201, 1212 (10th Cir. 2013)) contains no mention of an "oversight methodology," much less a determination that such a methodology must be used in equipment cost estimates for regional haze analysis.

The referenced 10th Circuit Court decision does, however, refer to the "overnight" cost estimation method. As explained in Section 2.4.1 of EPA's Control Cost Manual, this term refers to the procedure of estimating the capital cost of a project "...as if no interest was incurred during construction and therefore estimates capital cost as if the project is completed 'overnight'." The capital cost estimation procedures presented EPA's Control Cost Manual and Retrofit Cost Analyzer are "overnight" methods in that they exclude from the estimate the costs associated with financing the project during the construction period. The estimated cost to retrofit SCR to Unit 4 at Tracy Station was similarly developed in conformance with this methodology in that it excludes financing costs during construction.

Accordingly, the methodology used to develop the retrofit cost estimate for SCR on Unit 4 at Tracy Station is entirely consistent with the methodology described in EPA's Control Cost Manual.

NV Energy appreciates the opportunity to provide NDEP with additional information requested from Conservation Organizations regarding the four-factor analysis performed on both North Valmy and Tracy Generating Stations in development of Nevada's SIP for the Second Decadal Review period of the federal Regional Haze Program.

If you have additional questions please feel free to contact Chris Heintz at (702) 402-2048 or via email at christopher.heintz@nvenergy.com

Sincerely,

Mathew Johns
Vice President, Env. Services and Land Management
NV Energy

cc: Ken McIntyre, NDEP
Andrew Tucker, NDEP
Chris Heintz, NVE
Brigid McHale, NVE

Appendix G – Evidence of Public Participation and Nevada's Responses to Public Comments

Appendix G.1 - Evidence of Public Participation

Appendix G.2 - Request for Extension of Public Comment Period and NDEPs Response

Appendix G.3 - NV Energy Comments

Appendix G.4 - Conservation Organizations Comments

Appendix G.5 - NDEP Responsiveness Summary

Appendix G.1 – Evidence of Public Participation

- Notice of Public Hearing
- Public Hearing Agenda
- Proof of Publication
    - Nevada Division of Environmental Protection Website
    - Nevada Legislative Counsel Bureau Administrative Regulation Notices
    - Nevada Public Notice Website
    - Nevada Division of Environmental Protection AirInfo_Notices LISTSERV
    - Summary of Public Notice Distribution
- Public Hearing Cancellation Notice

Notice of Public Comment Period Beginning February 28, 2025, and a Public Hearing on April 4, 2025, If Requested

Pursuant to the public hearing requirements in Title 40 of the Code of Federal Regulations Part 51 Section 102, the Nevada Division of Environmental Protection (NDEP) is issuing the following notice and is taking comment on the proposed *Nevada Regional Haze Revision to the State Implementation Plan (SIP) for the Second Planning Period*.

On July 27, 2023, NDEP partially withdrew sections of its 2022 Regional Haze SIP due to changes in Nevada's energy landscape and transmission reliability. This SIP Revision replaces those withdrawn sections, and addresses certain requirements of 40 CFR part 51 section 308. NDEP will submit the final version of the proposed SIP Revision to the U.S. Environmental Protection Agency for approval into the Nevada Regional Haze SIP.

NDEP's SIP Revision for the Second Planning Period is available on the NDEP website at https://ndep.nv.gov/posts. Hard copies are available at NDEP Suite 4001, 901 S. Stewart Street, Carson City, NV 89701; NDEP Suite 200, 375 East Warm Springs Road, Las Vegas, NV 89119; and the Churchill County Library 553 S Maine St, Fallon, NV 89406. Access to the draft document may also be obtained by contacting Nicholas Schlafer at NDEP, 901 S. Stewart Street, Suite 4001, Carson City, NV 89701; (775) 687-9354; or e-mail to n.schlafer@ndep.nv.gov.

Persons wishing to comment on the proposed Regional Haze SIP Revision or to request a public hearing should submit their comments or request **in writing** to Nicholas Schlafer at NDEP, 901 S. Stewart Street, Suite 4001, Carson City, NV 89701; or e-mail to n.schlafer@ndep.nv.gov. ***A request for a hearing must be received by March 29, 2025. Written comments will be received by the NDEP until 5:00 PM PST, March 29, 2025, and will be retained and considered.*** Upon receipt of a valid written request, the NDEP will hold a public hearing on:

April 4, 2025
9:00 AM – 11:00 AM

Bonnie B. Bryan Boardroom **1st Floor** **901 S. Stewart Street** **Carson City, NV 89701**	**Warm Springs Conference Room** **Suite 200** **375 East Warm Springs Road** **Las Vegas, NV 89119**

Virtual Meeting Information via Microsoft Teams
Join on your computer or mobile app: Click here to join the meeting
Call In (audio only): +1 (775) 321-6111, Conference ID: 726 417 521#

Oral comments will be received at the Hearing. If no request for a public hearing is received by March 29, 2025, the hearing will be cancelled. Persons may check on the status of the hearing on the NDEP web site at https://ndep.nv.gov/posts or you may call the NDEP Bureau of Air Quality Planning at (775) 687-9354.

Members of the public who are disabled and require special accommodations or assistance at the meeting are requested to notify Ken McIntyre, (775) 687-9493; or e-mail kmcintyre@ndep.nv.gov no later than 3 working days before the workshop. This notice has been posted on the official State website, the Nevada Legislature website and the NDEP website, at the NDEP offices in Carson City and Las Vegas, at the State Library in Carson City and at County libraries throughout Nevada.

NEVADA DIVISION OF
ENVIRONMENTAL PROTECTION

STATE OF NEVADA
Department of Conservation & Natural Resources
Joe Lombardo, *Governor*
James A. Settelmeyer, *Director*
Jennifer L. Carr, *Administrator*

Public Hearing to Solicit Comments on Proposed *Nevada Regional Haze Revision to the State Implementation Plan for the Second Planning Period*

Upon receipt of a valid written request, the NDEP will hold a public hearing on:

April 4, 2025
9:00 AM – 11:00 AM

Bonnie B. Bryan Boardroom **1st Floor** **901 S. Stewart Street** **Carson City, NV 89701**	**Warm Springs Conference Room** **Suite 200** **375 East Warm Springs Road** **Las Vegas, NV 89119**

Virtual Meeting Information via Microsoft Teams
Join on your computer or mobile app: Click here to join the meeting
Call In (audio only): +1 (775) 321-6111, Conference ID: 726 417 521#

If receiving this document as a hard copy, you can access the meeting information at https://ndep.nv.gov/posts and search for the BAQP Hearing Notice

AGENDA
(No action items)

1. Welcome, introductions.

2. Review of agenda.

3. Presentation of proposed SIP Revision, including background information of the Regional Haze Rule, Round 2 State Implementation Plan, and timeline.

4. Public comments and questions on proposed SIP Revision. *

5. Adjourn

If no request for a public hearing is received by March 29, 2025, the hearing will be cancelled. Persons may check on the status of the hearing on the NDEP web site at **https://ndep.nv.gov/posts** or you may call the NDEP Bureau of Air Quality Planning at (775) 687-9354.

* Public comment may be limited to five minutes per person at the discretion of the chairperson. The chair reserves the right to dispense with repetitive comments on a given topic.

Members of the public who are disabled and require special accommodations or assistance at the meeting are requested to notify Ken McIntyre, (775) 687-9493; or e-mail kmcintyre@ndep.nv.gov no later than 3 working days before the workshop. This notice has been posted on the official State website, the Nevada Legislature website and the NDEP website, at the NDEP offices in Carson City and Las Vegas, at the State Library in Carson City and at County libraries throughout Nevada.

NEVADA DIVISION OF
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Jennifer L. Carr, *Administrator*

Public Notice

Memorandum

To: File

From: Nicholas Schlafer, BAQP

Date: 2/27/2025

Re: Website Update – Public Notice

This memorandum is to serve as an official record demonstrating the publication of a public notice on the Nevada Division of Environmental Protection Website. A screenshot of the public notice webpage is attached. The publication details of the public notice is as follows:

Proposed Action: Notice of Public Comment Period for Nevada's Regional SIP Revision

Publication URL: https://ndep.nv.gov/posts/ notice-of-public-comment-period-for-nevadas-regional-haze-sip-revision

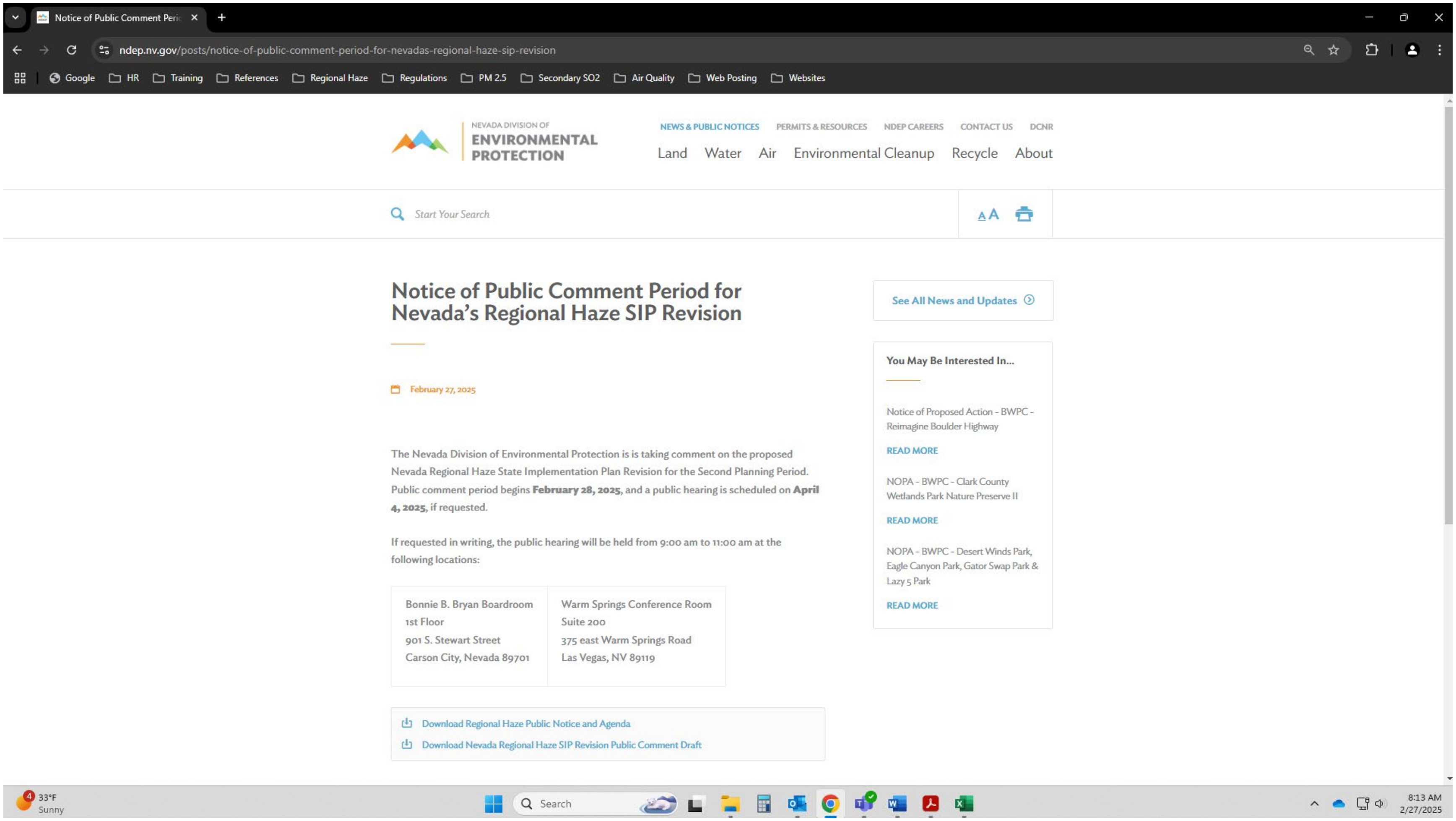
Date of Publication: 2/27/2025 **Time of Publication:** 8:00 AM

Beginning of Public Comment Period: 2/28/2025

End of Public Comment Period: 3/29/2025

Publication Expiration Date: 4/4/2025 **Time of Expiration:** 11:59 PM

Screenshot of Public Notice:



Notice of Public Comment Peri

ndep.nv.gov/posts/notice-of-public-comment-period-for-nevadas-regional-haze-sip-revision

Google | HR | Training | References | Regional Haze | Regulations | PM 2.5 | Secondary SO2 | Air Quality | Web Posting | Websites

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Notice of Public Comment Period for Nevada's Regional Haze SIP Revision

February 27, 2025

The Nevada Division of Environmental Protection is is taking comment on the proposed Nevada Regional Haze State Implementation Plan Revision for the Second Planning Period. Public comment period begins **February 28, 2025**, and a public hearing is scheduled on **April 4, 2025**, if requested.

If requested in writing, the public hearing will be held from 9:00 am to 11:00 am at the following locations:

Bonnie B. Bryan Boardroom 1st Floor 901 S. Stewart Street Carson City, Nevada 89701	Warm Springs Conference Room Suite 200 375 east Warm Springs Road Las Vegas, NV 89119

Download Regional Haze Public Notice and Agenda

Download Nevada Regional Haze SIP Revision Public Comment Draft

See All News and Updates

You May Be Interested In...

Notice of Proposed Action - BWPC - Reimagine Boulder Highway

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NOPA - BWPC - Desert Winds Park, Eagle Canyon Park, Gator Swap Park & Lazy 5 Park

READ MORE

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Administrative Regulation Notices

Meetings and Workshops

NRS 233B.0601 (/NRS/NRS-233B.html#NRS233BSec0601) (Added by AB 252 of the 77th (2013) Session)

Add a New Notice (/App/Notice/A/Submit)

Today is Monday, March 3, 2025

03/03/2025 11:00AM

Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/586_Hearing_Notice_March_3_2025.03032025.591.pdf)

Nevada Department of Agriculture (http://www.agri.nv.gov)

Notice of Intent to Act Upon a Temporary Regulation

Nevada Department of Agriculture 2300 E. St. Louis Avenue Las Vegas, NV 89104 and Nevada Department of Agriculture 4780 E. Idaho Street Elko, NV

03/08/2025 8:30AM

Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/CGR524NoticeofIntenttoAdopt.03082025.765.pdf)

Nevada Department of Wildlife (https://nvboardofwildlife.org/#notices)

Nevada Board of Wildlife Commissioners meeting

Clark County Government Center,

03/12/2025 9:00AM

Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/AdoptionHearingPacket.03122025.219.pdf)

NDWR - Nevada Division of Water Resources (https://water.nv.gov/)

Hearing for the Adoption of Temporary Regulations of the Nevada Division of Water Resources

Nevada Division of Resources Bryan Building, Bonnie Conference Room 901 S. Stewart St. Carson City, NV 89701

03/13/2025 2:30PM

Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/20250207_R157-24_REG_HRG_Notice_ADA.03132025.371.pdf)

Division of Insurance (https://doi.nv.gov/News-Notices/Regulations/)

Notice of Intent to Act Upon Regulation LCB File No. R157-24 and Hearing Agenda

Webex and Division of Insurance locations at 1818 E. College Pkwy., Ste. 103, Carson City, NV 89706 and 3300 W. Sahara Ave., Ste. 440, Las Vegas, NV 89102

03/19/2025 9:00AM

Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/Public_Notice_03192025_v2.03192025.579.pdf)

Nevada State Environmental Commission (https://sec.nv.gov/)

State Environmental Commission Regulatory Meeting

Bryan Building, First Floor, Bonnie B. Bryan Conference Room - 901 South Stewart Street, Carson City, Nevada VIRTUAL PARTICIPATION through Teams - see SEC website for link

03/28/2025 9:00AM

Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/NOIHRC032825.03282025.487.pdf)

Division of Human Resource Management (http://hr.nv.gov)

Human Resources Commission Meeting - Notice of Intent to Act Upon a Regulation

Nevada State Library and Archives Building, 100 N. Stewart Street, Room 110, Carson City, NV 89701 with videoconference to the Eureka Building, 7251 Amigo Street, Suite 120, Las Vegas, NV 89119

03/31/2025 10:00AM

Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/FinalNAC379HearingAgendaMarch2025.03312025.420.pdf)

Nevada State Library, Archives and Public Records (https://nsla.nv.gov/AdministrativeRegulations)

Notice Of Intent To Act Upon A Regulation

100 North Stewart Street Carson City, NV 89701

04/04/2025 9:00AM

Meeting Notice (http://www.leg.state.nv.us/App/Notice/Doc/Regional_Haze_Public_Notice_and_Agenda.04042025.241.pdf)

Nevada Division of Environmental Protection - Bureau of Air Quality Planning (https://ndep.nv.gov/)
Notice of Public Comment Period on Nevada's Regional Haze SIP Revision
901 S. Stewart St. Carson City, NV 89701 (Bonnie Conference Room 1st Floor)

Nevada Public Notice Website

Government

State

City

County

K-12

Higher Education

Special Districts

Entity

Department of Education

Department of Employment Training and Rehabilitation

Department of Health and Human Services

Department of Indigent Defense Services

Department of Motor Vehicles

Department of Public Safety

Public Body

Division of Environmental Protection

Division of Forestry

Results for Division of Environmental Protection

Results are limited to the last 7 days and for all dates in the future.

Notice	Date Posted	Event Date	Time	Status	Type
Notice of Public Comment Period on Nevadas Regional Haze SIP Revision (https://ndep.nv.gov/posts/notice-of-public-comment-period-for-nevadas-regional-haze-sip-revision)	2/27/2025	4/4/2025	9:00 AM	Scheduled	Hearing

Today's Meetings

12:00 AM	Nevadaworks (http://www.nevadaworks.com)
08:00 AM	South Lyon County Hospital District (http://www.SLMCNV.org)
08:30	Carson Water Subconservancy District (https://www.cwsd.org/wp-content/uploads/2025/02/

Email Address, No Website | Link to Website

Public Notice Access

Public Bodies wishing to post public notices must first register (/Account/Register) for an account. *It is recommended to use your government issued email address.*

From:	Nicholas Schlafer
To:	airinfo_notices@listserv.state.nv.us
Cc:	Ken McIntyre
Subject:	Notice of Public Comment Period
Date:	Thursday, February 27, 2025 2:04:00 PM
Attachments:	Regional_Haze_Public_Notice_and_Agenda.pdf

Please find attached, for your information, a notice of public comment period and agenda with information on how to access related materials. The Nevada Division of Environmental Protection is taking comment on the proposed Nevada Regional Haze SIP Revision for the Second Planning Period.

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
775-687-9354

NEVADA DIVISION OF ENVIRONMENTAL PROTECTION

Nevada Department of Conservation & Natural Resources

Connect with us:

From:	LISTSERV.STATE.NV.US LISTSERV Server (17.0)
To:	Nicholas Schlafer
Subject:	Your message dated Thu, 27 Feb 2025 22:04:31 +0000 with...
Date:	Thursday, February 27, 2025 2:05:41 PM

Your message dated Thu, 27 Feb 2025 22:04:31 +0000 with subject "Notice of Public Comment Period" has been successfully distributed to the AIRINFO_NOTICES list (224 recipients).

Summary of Public Notice Distribution for Nevada's Regional Haze SIP Revision Public Comment Period starting 2/28/25 and ending 3/29/2025, in preparation for the 4/4/25 Public Hearing, if requested. Sent out 2/27/25; grand total of recipients is 951.

Mailing List:	Number of Recipients:
• **General List**	3
→ NGO-1	
→ Public-1	
→ Libraries-1	
• **County Commissioners**	18

Listservs:

• **Air Info**	224
• **Air Consultants**	18
• **Class I/II Permittees**	444

Email List:

• **Environmental Organizations**	13
• **General List**	37
→ Industry-12	
→ Federal-6	
→ EPA-10	
→ DCNR-3	
→ State-3	
→ Local-3	
• **Libraries**	20
• **Tribal Organizations**	22
• **Regional Planning Agencies**	5
• **Legislators**	59
• **Newspapers**	12
• **NDEP Air Groups**	66
• **Las Vegas DEP**	2
• **NV Energy**	4
• **Lhoist Apex**	4

Grand Total: 951

STATE OF NEVADA
Department of Conservation & Natural Resources
Joe Lombardo, *Governor*
James A. Settelmeyer, *Director*
Jennifer L. Carr, *Administrator*

NOTICE OF CANCELLATION OF PUBLIC HEARING ON APRIL 4, 2025

Nevada Division of Environmental Protection
Bureau of Air Quality Planning

Pursuant to the public hearing provisions in Title 40 of the Code of Federal Regulations Part 51 section 102, the Nevada Division of Environmental Protection (NDEP) is cancelling the following public hearing because no request for a hearing was received:

April 4, 2025
9:00 AM – 11:00 AM

Bonnie B. Bryan Boardroom **1st Floor** **901 S. Stewart Street** **Carson City, NV 89701**	**Warm Springs Conference Room** **Suite 200** **375 East Warm Springs Road** **Las Vegas, NV 89119**

The proposed Nevada Regional Haze Revision to the State Implementation Plan for the Second Planning Period, along with related materials, are available on the NDEP website at https://ndep.nv.gov/posts/notice-of-public-comment-period-for-nevadas-regional-haze-sip-revision. Persons may also check on the status of the Nevada Regional Haze SIP revision by telephone at (775) 687-9354.

Appendix G.2 – Request for Extension of Public Comment Period and NDEPs Response

March 13, 2025

Via electronic mail

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

Re: **Requesting Extension of Public Comment Period for Nevada's Regional Haze SIP Revision**

Dear Mr. Schlafer,

On behalf of Coalition to Protect America's National Parks ("CPANP"), National Parks Conservation Association ("NPCA") and Sierra Club (together, the "Organizations"), we request that the Nevada Division of Environmental Protection ("NDEP") grant an extension of the public comment deadline for Nevada's Regional Haze SIP Revision ("SIP Revision"), currently noticed for public comment.[1] Specifically, we ask that the current deadline for comments, Monday, March 31st, 2025, be extended to Monday, April 14th, 2025.

The SIP Revision is a 300-page document that substantially revises the four-factor analyses for two sources, the North Valmy and Tracy generating stations, and incorporates permit updates at two other sources. The North Valmy analysis represents the greatest change from the 2022 SIP submission, as the plant is now planned for conversion from coal to gas-fired operations. Given that scope and complexity,[2] the Organizations believe that the current comment period is not sufficient to fully analyze the potential impacts of the SIP Revision and provide meaningful comment. Reviewing NDEP's technical analysis along with its modeling, conducting any analysis of our own, comparing the SIP Revision to the original SIP Submission and developing comments, requires more time than allowed by the current comment period, which ends on March 31st. A 14-day extension of the deadline will not prejudice any regulated

[1] See Nevada's public notice:
https://ndep.nv.gov/uploads/documents/Regional_Haze_Public_Notice_and_Agenda.pdf

[2] See Nevada's Regional Haze SIP Revision:
https://ndep.nv.gov/uploads/documents/NV_RH_SIP_Revision_Public_Comment_Draft.pdf

entity and will not materially affect NDEP's ability to submit its SIP to EPA within a reasonable time. The deadline for EPA to act on Nevada's SIP submission and SIP Revision is not until December 2025. A 14-day extension of NDEP's comment period would not substantially alter NDEP's timeline to submit the SIP Revision to EPA, and would still allow ample time for EPA to meet its December 2025 deadline.

A modest extension of the public comment period will not adversely impact any other party. We understand and appreciate that NDEP has provided periodic stakeholder updates throughout the planning process, but we have not had access to the SIP Revision before its release on February 27th, 2025.

Critically, NDEP did not notify Sierra Club, NPCA, or CPANP of the availability of the SIP Revision. None of the undersigned representatives of the Organizations received notice of the current comment period, even those individuals who subscribe to NDEP email lists and have been notified by NDEP of other Regional Haze-related notices in the past. For example, NDEP provided email notice of a public comment period on the proposed Nevada Regional Haze Progress Report for the Second Planning Period in December 2024, but the Organizations did not receive an equivalent email notice for this comment period. As a result, the Organizations did not learn of the SIP revision until almost two weeks after its issuance.

Conversely, given the scope and complexity of the SIP Revision, the current March 31st deadline for comments will effectively preclude the Organizations from reviewing all of the relevant technical data supporting the rule, fully analyze the SIP Revision compared to the original SIP Submission, and providing meaningful legal and technical comments.

Ultimately, if finalized as currently proposed, the SIP Revision would adversely affect the Organizations' interests in pollution reduction, the environment, as well the health and welfare of our members and their use and enjoyment of protected national parks and wilderness areas. We respectfully ask that you grant our request by Wednesday, March 19th, so that we can plan our comments most efficiently.

Respectfully submitted,

Patrick Woolsey
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Philip A. Francis, Jr.
Chair
Coalition to Protect America's National Parks
Washington, DC
Editor@protectnps.org

March 19, 2025

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RE: Requesting Extension of Public Comment Period for Nevada's Regional Haze SIP Revision

Dear Mr. Woolsey, Mr. Shrinath, Mr. Rose, and Mr. Francis,

On March 13, 2025, the Nevada Division of Environmental Protection (NDEP) received a letter submitted on behalf of the Coalition to Protect America's National Parks, the National Parks Conservation Association, and Sierra Club (Organizations) requesting an extension of the public comment period for Nevada's Regional Haze State Implementation Plan Revision for the Second Planning Period (SIP). The letter requested that the public comment period for the SIP be extended from March 31, 2025, to April 14, 2025, noting that the Organizations do not believe that 32 days is sufficient to review the SIP, complete their own analysis, compare the SIP Revision to the original SIP and develop comments. The Organizations further note that they were not notified of the availability of the SIP Revision and did not learn of the SIP Revision until almost two weeks after the start of the public comment period on February 28, 2025, despite having been notified of Regional Haze-relate notices in the past. NDEP also received communication from Ms. Natalie Levine of the National Parks Conservation Association on

March 6, 2025, requesting an extension of the SIP Revision comment period from March 28, 2025, to March 31, 2025, which was granted by the NDEP.

The NDEP understands and sympathizes with the Organizations' concerns about having adequate time to able to make meaningful comments on the SIP; however, NDEP must also allow for adequate time to consider and address public comments from all interested parties. NDEP must submit its SIP Revision to the United States Environmental Protection Agency (EPA), allowing sufficient time, so that the EPA can complete its own review and comment period before December 15, 2025, the date by which it must sign a notice of final rulemaking on Nevada's Regional Haze SIP as required by Consent Decree Sierra Club, et al. v. EPA, et al., No. 1:23-cv-01744-JDB.

NDEP made the notice of public comment period for the SIP Revision available through the same website postings and email lists it used for the 2025 Regional Haze Progress Report which was received by the Organizations in December 2024. The public can receive notices from NDEP Bureau of Air Quality Planning by going to https://ndep.nv.gov/, clicking on "Get Notices" at the bottom of the page and then selecting "Air Quality Info and Notices" and entering their email. Recipients of these email lists included four members of the Sierra Club and one member of the National Parks Conservation Association.

If NDEP were to grant the requested extension it would cut the available time to consider and address public comments before NDEP must submit the SIP Revision to the EPA, NDEP does not believe a further extension of the comment period is necessary. The NDEP respectfully declines to grant the requested extension to the public comment period.

If you have any questions, please feel free to contact me by email at kmcintyre@ndep.nv.gov or by phone at 775-687-9493.

Regards,

Ken McIntyre
Supervisor, Planning Branch
Bureau of Air Quality Planning

NS/KM

EC:
Patrick Woolsey, Staff Attorney, Sierra Club
Nihal Shrinath, Staff Attorney, Sierra Club
Mark Rose, Sierra Nevada & Clean Air Program Manager, National Parks Conservation Association
Michael Murray, Chair, Coalition to Protect America's National Parks
Philip A. Francis, Jr., Chair, Coalition to Protect America's National Parks
Danilo Dragoni, Ph.D, Deputy Director, BAQP
Andrew Tucker, Chief, BAQP

Appendix G.3 – NV Energy Comments

March 21, 2025

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: Nevada Regional Haze Revision to the State Implementation Plan (SIP) for the Second Planning Period

Dear Mr. Schlafer,

NV Energy (NVE) respectfully submits these comments in response to the proposed "Nevada Regional Haze Revision to the State Implementation Plan (SIP) for the Second Planning Period" (Proposed SIP Revision).

The Proposed SIP Revision, Appendix A.2 – Tracy Generating Station, NV Energy – contains provisions in the "Notification of Issuance of 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" cover letter dated March 23, 2022 and enclosed permit (minus strikeout) to be incorporated and adopted into the Proposed SIP Revision by reference. NVE has the following comments:

- PDF page 93 of 302 regarding System 33 – Combined Cycle Combustion Turbine Circuit No. 9 – Pipeline Quality Natural Gas – 252 MW Nominal Output, Section M.1.b. CO and VOC emission from S2.066 and S2.067 shall be controlled by an Oxidation catalyst for control. NVE requests this condition to be in strikeout (not included) same as Section IV.L.1.b for System 32 – Combined Cycle Combustion Turbine Circuit No. 8 on page 89 of 302 as follows:

  ~~b. CO and VOC emission from S2.066 and S2.067 shall be controlled by an Oxidation catalyst for control.~~

- PDF page 99 of 302, Section V. Continuous Emissions Monitoring system (CEMS) Conditions (continued), A.8.c.(1)(c) – Annual 2-load flow RATA or annual 3-load flow RATA. The requirement to conduct a flow relative accuracy test audit (RATA) is not applicable to the facility as Tracy Station units all qualify as "gas-fired" as defined in 40CFR72.2. Under 40CFR75, gas-fired units are not required to use a flow monitor to measure sulfur dioxide (SO_2) and carbon dioxide (CO_2) mass emissions or heat input rate (40CFR75.10, 40CFR75.11, 40CFR75.13, 40CFR75 App. D, 40CFR75 App F). This condition should be in strikeout as follows:

~~(c) Annual 2-load flow RATA or annual 3-load flow RATA.~~

We appreciate the opportunity to provide comments for your consideration and we look forward to EPA approval of the Proposed SIP Revision. If you have any questions about these comments, please contact Chris Heintz at your earliest convenience.

Sincerely,

Mathew Johns
Vice President, Environmental Services and Land Management
NV Energy

cc: Ken McIntyre (kmcintyre@ndep.nv.gov)
Chris Heintz (Christopher.Heintz@nvenergy.com)

Appendix G.4 – Conservation Organizations Comments

March 31, 2025

Nicholas Schlafer
Environmental Scientist
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Re: Comments on Proposed Supplement to the Nevada Regional Haze Revision to the State Implementation Plan (SIP) for the Second Planning Period

Dear Mr. Schlafer,

The National Parks Conservation Association ("NPCA"), Sierra Club, and the Coalition to Protect America's National Parks (collectively, "Conservation Organizations") submit the following comments on the Nevada Division of Environmental Protection's ("NDEP") Supplement ("2025 SIP Supplement")[1] to its Regional Haze State Implementation Plan for the Second Implementation Period submitted to the Environmental Protection Agency ("EPA") on August 12, 2022 ("2022 SIP Revision").[2] The Conservation Organizations submitted public comments, including an expert report prepared by Joe Kordzi ("2022 Kordzi Report"), to NDEP on the 2022 SIP Revision on July 25, 2022.[3]

[1] NDEP, Nevada Regional Haze Revision to the State Implementation Plan for the Second Planning Period (Feb. 28, 2025) [hereinafter "2025 SIP Supplement"].
[2] NDEP, Nevada Regional Haze State Implementation Plan for the Second Planning Period (Aug. 2022) [hereinafter "2022 SIP Revision"].
[3] NPCA, et al., Conservation Organizations' Comments on the Nevada Division of Environmental Protection's Proposed Regional Haze State Implementation Plan for the Second Planning Period (July 25, 2022) [hereinafter "Conservation Organizations 2022 SIP Revision Comments"] (attached as Ex. 1); Conservation Organizations 2022 SIP Revision Comments, Ex. 1, Joe Kordzi, A Limited Review of the Nevada Regional Haze State Implementation Plan (July

The Conservation Organizations are active nationwide in advocating for strong air quality requirements to protect our national parks and wilderness areas. These groups have long participated in Regional Haze SIP comment periods, rulemakings, and litigation across the country to ensure that states and EPA satisfy their obligations under the Clean Air Act and the Regional Haze Rule ("RHR"). The Conservation Organizations' members who live in Nevada—including NPCA's over 14,000 members and supporters, Sierra Club's over 4,500 members and the Coalition's 27 current members and others who have lived and/or worked in Nevada throughout their careers with the National Park Service ("NPS")—use and enjoy regional Class I areas that are impacted by Nevada's sources of haze-forming pollution.

NDEP's proposed SIP Supplement does not address many of the issues raised in the Conservation Organizations' comments on the 2022 SIP Revision nor issues raised in the expert report from Joe Kordzi, submitted to the State in July 2022. Additionally, although the SIP Supplement includes additional Four-Factor Analyses for two facilities—the Valmy and Tracy Electric Generating Units ("EGUs")—those analyses are highly flawed. As discussed in more detail below:

- NDEP set an appropriate and reasonable cost-effectiveness threshold of $10,000/ton of pollution reduced to evaluate available controls in the second planning period that recognizes the iterative nature of the Regional Haze Program.
- Although NDEP updates and revises its Four-Factor Analyses for the North Valmy and Tracy EGUs, the agency relies on highly flawed facility-submitted control cost analyses, causing the State to improperly reject feasible, available, and cost-effective control options that would achieve significant emission reductions during this planning period.
- When those analytical errors are corrected, it is clear that NDEP should have selected selective catalytic reduction ("SCR") instead of selective non-catalytic reduction ("SNCR") as the reasonable progress measure at North Valmy.
- In order to ensure maintenance of low emissions at Tracy Units 5 and 6, NDEP should have limited the generation hours of those two units in the SIP supplement.
- NDEP should have selected SNCR as a reasonable progress measure at Tracy, as required by federal and state law.
- The regulatory and permit provisions that NDEP proposes to incorporate into the SIP via this SIP Supplement are vague and do not include adequate monitoring, recordkeeping, and reporting requirements to ensure that the emission limits relied upon to make reasonable progress are met and enforced.
- NDEP inappropriately adjusted the uniform rate of progress glidepath for the Jarbidge Wilderness Area, obscuring the fact that the 2028 reasonable progress goal for the Jarbidge Wilderness Area is above the unadjusted glidepath for that Class I area.

2022) [hereinafter "2022 Kordzi Report"] (attached as Ex. 2). Mr. Kordzi is an independent air quality consultant and engineer with extensive experience in the regional haze program.

The Conservation Organizations also submit a report prepared by Joe Kordzi ("2025 Kordzi Report"), an air pollution expert with over thirty-six years of experience, which is attached and incorporated by reference into these comments.[4]

[4] Joe Kordzi, A Partial Review of the Nevada Regional Haze State Implementation Plan Revision (Mar. 2025) [hereinafter "2025 Kordzi Report"] and Exhibits (attached as Ex. 3 through 3g).

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I. Improving Visibility in Class I Areas Will Result in Economic, Public Health, and Environmental Benefits.

Nevada is home to one Class I area: Jarbidge Wilderness Area. This protected area provides habitat for a range of wildlife species, and provides year-round recreational opportunities for residents and visitors. It also preserves remote and rugged landscapes in northeastern Nevada.[5]

Because this area is designated as "Class I" under the Clean Air Act, its air quality is entitled to the highest level of protection. In spite of that, the Jarbidge Wilderness Area is still affected by more than two dozen sources of pollution in Nevada and other states that harm its air quality and viewsheds.[6] Today, iconic wilderness areas and national parks are marred by air pollution that diminishes long range scenic views and robs visitors of their connection to and appreciation of large landscapes. Much of the air pollution in these Class I areas stems from power plant and other industrial facility emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NOx"), which react in the atmosphere to form "haze" pollution many miles downwind of the sources.

Beyond Nevada's own Class I areas, in-state pollution sources impact Class I areas in other nearby states, including iconic national parks like Grand Canyon in Arizona, Glacier in Montana, and Kings Canyon and Sequoia in California.[7] According to NPCA's 2024 Polluted Parks Report, Sequoia and Kings Canyon National Parks are the two most polluted parks in the nation for both the health-harming and haze-forming air pollution.[8] To effectively address air pollution in Kings Canyon and Sequoia, other states like Nevada must take steps to reduce their share of pollution that travels hundreds of miles, negatively affecting the Park's air quality.

Class I areas are an important component of Nevada's economy, as well as the economies of other states in the region. Class I parks and wilderness areas draw hundreds of thousands of visitors from around the world each year, providing a boon to gateway communities and local recreation businesses.[9] In 2023, outdoor recreation activities in the state contributed $8.1 billion

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[5] Nev. Dep't Wildlife, Jarbidge Wilderness (last visited Mar. 19, 2025), https://www.ndow.org/nevadawildlifediscoverytrail/jarbidge-wilderness/.

[6] NPCA, Regional Haze Interactive Map (last visited Mar. 11, 2025), https://experience.arcgis.com/experience/46dd650b65284b64bf38ccba0e90af8b/?org=npca.

[7] *Id.*

[8] NPCA, Polluted Parks: How Air Pollution and Climate Change Continue to Harm America's National Parks at 5, 7 (2024), https://www.npca.org/reports/air-climate-report [hereinafter "Polluted Parks 2024"] (attached as Ex. 4).

[9] U.S. Forest Serv., National Visitor Use Monitoring Survey Results: National Summary Report (Sept. 2023), https://www.fs.usda.gov/sites/default/files/2022-National-Visitor-Use-Monitoring-Summary-Report.pdf (providing information on visitation to national forests and wilderness areas from FY 2018 through FY 2022) (attached as Ex. 5); NPS, 2023 National Park Visitor Spending Effects (Aug. 2024), https://www.nps.gov/subjects/socialscience/vse.htm (attached as Ex. 6).

in value to Nevada's economy, supporting more than 58,000 jobs.[10] However, when the air at a Class I area is polluted, visitation can drop by eight percent, harming local economies.[11] Air quality directly affects public use and enjoyment of our national parks and wilderness areas. As a result, a strong regional haze plan for Nevada is necessary to improve visibility at Jarbidge Wilderness Area, as well as other Class I areas in the region, to protect this critical contributor to local and state economies.

Reducing air pollution through Nevada's regional haze SIP would also improve public health, particularly for communities surrounding the State's various sources of air pollution. The same pollutants that mar scenic views at national parks and wilderness areas also cause adverse public health impacts. For example, NOx pollution is a precursor to ground-level ozone, which is associated with increased incidences of respiratory diseases, asthma attacks, and decreased lung function.[12] NOx reacts with other compounds in the air to form particulates that can cause and worsen respiratory diseases, aggravate heart disease, and lead to premature death.[13] Similarly, SO_2 worsens asthma and other respiratory symptoms and can form particulates that aggravate respiratory and heart diseases and cause premature death.[14] Particulate matter ("PM") can penetrate deep into the lungs and cause a host of health problems, such as aggravated asthma, decreased lung function, and heart attacks.[15] NOx and SO_2 emissions also harm terrestrial and aquatic plants and animals through acid rain and nitrogen deposition, which in turn causes ecosystem changes, like eutrophication of mountain lakes.[16]

II. Nevada's Supplement Source-Specific Analyses and Control Determinations Are Flawed.

When determining the reasonable progress measures for a source under the Regional Haze Program, the Clean Air Act requires states to consider four statutory factors: the costs of

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[10] Bureau Econ. Analysis, Outdoor Recreation Satellite Account (ORSA): 2023—Nevada (2025), https://apps.bea.gov/data/special-topics/orsa/summary-sheets/ORSA%20-%20Nevada.pdf (attached as Ex. 7).
[11] *See* David Keiser et al., Air pollution and visitation at U.S. national parks, 4 Sci. Advances 3-6 (July 18, 2018), https://www.science.org/doi/10.1126/sciadv.aat1613 (attached as Ex. 8).
[12] EPA, Health Effects of Ozone Pollution (last updated Mar. 13, 2025), https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution (attached as Ex. 9).
[13] EPA, Basic Information About NO_2 (last updated July 16, 2024), https://www.epa.gov/no2-pollution/basic-information-about-no2#:~:text=Nitrogen%20Dioxide%20(NO2)%20is,larger%20group%20of%20nitrogen%20oxides (attached as Ex. 10); EPA, Health and Environmental Effects of Particulate Matter (PM) (last updated July 16, 2024), https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm [hereinafter "EPA PM Effects"] (attached as Ex. 11).
[14] EPA, Sulfur Dioxide Basics (last updated Jan. 10, 2025), https://www.epa.gov/so2-pollution/sulfur-dioxide-basics (attached as Ex. 12); EPA PM Effects.
[15] EPA PM Effects.
[16] Polluted Parks 2024 at 8-9; EPA PM Effects; EPA, Ecosystem Effects of Ozone Pollution (last updated Oct. 21, 2024), https://www.epa.gov/ground-level-ozone-pollution/ecosystem-effects-ozone-pollution (attached as Ex. 13).

compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of the source.[17] The Regional Haze Rule, in turn, tasks states, not regulated facilities, with complying with the requirements of the Act.[18] Thus, where a facility submits its own Four-Factor Analysis, the state must independently review that analysis and ensure that it is accurate, complete, and adequately documented.[19]

To assess controls analyzed in accordance with the statutory factors, NDEP set an appropriate cost-effectiveness threshold that recognizes the need to adopt new, additional control measures to make reasonable progress toward the natural visibility goal, in line with EPA guidance. However, rather than conduct its own independent review for Valmy and Tracy, NDEP relies entirely on facility-submitted Four-Factor Analyses that are riddled with errors for both facilities. NDEP must correct the numerous errors in those analyses discussed below and require both facilities to install feasible, available, and cost-effective controls that will achieve significant emission reductions during this planning period.

A. NDEP's Cost-Effectiveness Threshold for the Second Planning Period Is Reasonable and Appropriate.

For this planning period, NDEP set a $10,000/ton of pollution reduced cost-effectiveness threshold to assess and select emission reduction measures that are necessary to make reasonable progress.[20] NDEP's cost threshold is reasonable and appropriately meets requirements for assessing the Clean Air Act's four statutory factors.

NDEP explained that its chosen cost-effectiveness threshold was double what the State used to assess Best Available Retrofit Technology ("BART") during the first implementation period,[21] which started nearly two decades ago in 2008.[22] Thus, NDEP selected its threshold "to ensure that the entire fleet of potential new control measures throughout Nevada are thoroughly considered, as well as, to ensure that enough controls are implemented during the second period to continue achieving reasonable progress at Jarbidge WA and other out-of-state [Class I

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[17] 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(f)(2)(i).
[18] *See* 40 C.F.R. § 51.308(f)(2)(i) ("*The State* must evaluate and determine the emission reduction measures that are necessary to make reasonable progress . . . . *The State* should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. *The State* must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration . . . .") (emphasis added)).
[19] 40 C.F.R. § 51.308(f)(2)(iii); Memorandum from Peter Tsirigotis, Dir., EPA, to Reg'l Air Dirs., Regions 1-10 at 32 (Aug. 20, 2019), https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf [hereinafter "2019 Guidance"] (explaining that "every source-specific cost estimate used to support an analysis of control measures must be documented in the SIP") (attached as Ex. 14).
[20] 2022 SIP Revision at 5-6; 2025 SIP Supplement at 1-2, 2-6.
[21] 2022 SIP Revision at 5-6.
[22] 82 Fed. Reg. 3078, 3082 (Jan. 10, 2017) (noting that the first planning period covered the years 2008 to 2018).

areas]."[23] The State's rationale for its $10,000/ton cost threshold is, thus, reasonably moored to achieving the goals of the Act—namely, to make progress toward achieving natural visibility conditions during each iterative planning period.[24]

NDEP's threshold is also in line with appropriate thresholds adopted by other states, such as Colorado and New Mexico, which both also adopted a $10,000/ton cost threshold for their second planning period SIPs.[25] Indeed, just as NDEP explained in the 2022 SIP Revision, Colorado similarly noted that its selection of a threshold value of $10,000 per ton of pollution reduced, "is an increase from Round 1 and reflects the fact that with each successive round of planning, less costly and easier to implement strategies have already been adopted."[26]

B. NDEP Should Have Provided More Information About Impacted Class I Areas.

The Conservation Organizations explained in their 2022 comments that NDEP's 2022 SIP proposal did not provide sufficient information about the specific Class I areas impacted by each source.[27] NDEP's 2025 SIP Supplement does not remedy this problem. For example, while the SIP Revision identifies Jarbidge Wilderness Area as the Class I area closest to North Valmy, NDEP still does not identify other Class I areas impacted by the plant, and does not provide Q/d values for any of those other areas. NDEP must provide more information about how each source contributes to visibility impairment in Class I areas, including those in neighboring states, not just the Class I area nearest to the source.[28]

C. NDEP's Four-Factor Analysis for Valmy Contains Significant Flaws and Underestimates the Cost-Effectiveness of SCR and SNCR for Units 1 and 2.

1. Background

North Valmy Generating Station is a power plant with two coal-fired steam generating units operated by Sierra Pacific Power Company d/b/a NV Energy. North Valmy is the largest

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[23] 2022 SIP Revision at 5-6.

[24] 42 U.S.C. § 7491(a)(1) (establishing "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution"); *see North Dakota v. EPA*, 730 F.3d 750, 760-62 (8th Cir. 2013) (citing *Alaska Dep't Env't Conservation v. EPA*, 540 U.S. 461, 485, 490 (2004)).

[25] In the Matter of Proposed Revisions to Regulation Number 23, Colo. Dep't Pub. Health & Env't, Air Pollution Control Div., Prehearing Statement at 7 (Oct. 7, 2021) [hereinafter "Colorado SIP Revision"] (attached as Ex. 15); Excerpt of N.M. Env't Dep't, Air Quality Bureau, State of New Mexico Revised Proposed Regional Haze State Implementation Plan Revision Second Planning Period (2019 – 2028) at xiii, 103 (revised Feb. 7, 2025), https://cloud.env.nm.gov/resources/_translator.php/OTI5MTYyMThlZDhlMTUyZGRkYTJiNDBmNV8xODMxNTA~.pdf (excerpt attached as Ex. 16).

[26] Colorado SIP Revision at 7.

[27] Conservation Organizations 2022 SIP Revision Comments at 16.

[28] *See* 40 C.F.R. § 51.308(d)(3), (d)(3)(i).

source of visibility-impairing pollution in the state of Nevada, and causes visibility problems in approximately ninety-one Class I areas, including the Jarbidge Wilderness Area in Nevada as well as national parks and wilderness areas in neighboring states. Unit 1 is 277 MW and has NOx combustion controls but no post-combustion NOx or SO_2 controls, except for a lime-based dry sorbent injection ("DSI") system designed to control hydrogen chloride emissions.[29] Unit 2 is 290 MW and has NOx combustion controls and a dry lime scrubber for SO_2 control.[30]

Prior to 2024, both of the North Valmy units were scheduled to retire by December 31, 2028. Accordingly, in its 2022 draft SIP revision, NDEP proposed to identify retirement of North Valmy Units 1 and 2 by December 31, 2028 as a reasonable progress measure, and did not identify other controls as necessary to satisfy reasonable progress.[31] In July 2022, the Conservation Organizations submitted comments explaining that, while retirement of the North Valmy units would have long-term benefits for visibility improvement in Class I areas, NDEP should have evaluated cost-effective emissions control measures to further reduce haze pollution before the end of the second implementation period in 2028.[32] Specifically, the Conservation Organization's comments explained that NDEP should have (1) considered NOx combustion control upgrades, (2) documented Unit 1's DSI effectiveness and investigated upgrades, and (3) documented the scrubber efficiency for Unit 2 and investigated upgrades.[33]

However, in March 2024, the Nevada Public Utilities Commission ("PUCN") approved a plan submitted by NV Energy to cancel the retirement of North Valmy Units 1 and 2, and instead repower them with natural gas by 2026. In response, NDEP has modified the proposed Nevada SIP to include four-factor analyses for these units.[34] NDEP's four-factor determination for the North Valmy units is adopted from and relies on a four-factor analysis prepared by NV Energy, which is provided as an appendix to the SIP.[35]

2. The Four-Factor Analysis for North Valmy in NDEP's SIP Supplement Has Significant Flaws.

The Conservation Organizations commend NDEP for preparing a Four-Factor Analysis of additional NOx emissions controls for the North Valmy steam units after their planned conversion from coal to gas, rather than simply assuming that the planned gas conversion would be sufficient to make reasonable progress without analyzing additional controls for the gas-fired units.

NDEP's revised Four-Factor Analysis for the North Valmy units evaluated selective catalytic reduction ("SCR"), selective non-catalytic reduction ("SNCR"), and flue gas

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[29] 2025 Kordzi Report at 2.
[30] *Id.*
[31] 2022 SIP Revision at 5-7 (Tbl. 5-5).
[32] Conservation Organizations 2022 SIP Revision Comments at 15.
[33] *Id*. at 17-22.
[34] 2025 SIP Supplement at 2-1 to 2-8.
[35] 2025 SIP Supplement, Appendix B, Regional Haze Reasonable Further Progress: Updated Four Factor Analysis, NV Energy North Valmy and Tracy Generating Stations, prepared for NV Energy by AECOM Technical Services, Inc. (Mar. 2024).

recirculation ("FGR") as potential emissions control technologies.[36] NDEP's analysis uses a $10,000 per ton cost threshold to determine cost effectiveness, deeming controls with costs per ton above that threshold to be not cost effective.[37] NDEP concluded that SNCR and FGR would fall below this threshold and would be cost-effective.[38] However, NDEP concluded that the cost per ton of SCR would fall above the threshold and would therefore not be cost effective.[39] Of the three control technologies, NDEP found that SNCR would be the most cost-effective, and therefore concluded that SNCR and its associated NOx limit are necessary to achieve reasonable progress.[40] However, NDEP found that FGR or SCR are acceptable alternatives as long as a 0.102 lb/MMBtu NOx emission limit is met.[41]

As noted above, the Conservation Organizations retained air pollution expert Joe Kordzi to prepare a report evaluating NDEP's revised Four-Factor Analysis for North Valmy.[42] Mr. Kordzi's report identifies several significant problems in NDEP's Four-Factor Analysis for the North Valmy units that undermine the SIP's conclusions. Specifically, Mr. Kordzi concludes that (1) the NOx emissions baseline, electricity generation projections, and inlet NOx rate are unsupported or undocumented, (2) the efficiency assumptions for SCR and SNCR are too low, and (3) NDEP's analysis uses incorrect or unsupported inputs to calculate the cost-effectiveness of controls (including annual MWh Output, net plant heat rate, Inlet and Outlet SNCR NOx Rates, normalized Stoichiometric Ratio, concentration and cost of reagent, Chemical Engineering Plant Cost Index, cost of electricity, and fuel cost).[43]

As a result of these flaws, NDEP's four-factor determination significantly overestimates the costs per ton of emissions reduction for SCR and SNCR at North Valmy, and therefore underestimates the cost-effectiveness of those technologies. Mr. Kordzi's report calculates that the actual costs per ton of SNCR and SCR at Valmy Units 1 and 2 are roughly half of NDEP's estimates.[44] NDEP's conclusion that SCR is not cost-effective is incorrect and unsupported. In fact, SCR is a cost-effective control measure at both North Valmy units, and well below NDEP's $10,000 per ton cost threshold, as will be explained below. Mr. Kordzi's report shows that SNCR is also more cost-effective than NDEP acknowledges. But while NDEP is correct that SNCR and FGR are also cost-effective control measures, SNCR or FGR would reduce significantly less NOx emissions than SCR. Given that SCR is cost-effective and would maximize NOx reductions, NDEP's decision not to select SCR as a reasonable progress measure is unreasonable.

The National Park Service's review of NDEP's revised SIP affirms Mr. Kordzi's conclusions that SCR is cost-effective for North Valmy Units 1 and 2 and would reduce

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[36] 2025 SIP Supplement at 2-3 to 2-5.
[37] *Id*. at 2-6.
[38] *Id.*
[39] *Id*. at 2-5 to 2-6.
[40] *Id.* at 2-6.
[41] *Id.* at 2-6 to 2-7.
[42] *See* 2025 Kordzi Report.
[43] 2025 Kordzi Report at 3-20.
[44] *Id*. at 13-20.

significantly more NOx emissions per year than SNCR.[45] NPS recommends that NDEP should require SCR as the reasonable progress measure for both North Valmy units.[46] NPS also recommends that if NDEP determines that SCR is not cost-effective on the basis of limited utilization, NDEP should include a federally-enforceable limit on individual unit utilization.[47] The Conservation Organizations support both of these NPS recommendations.

3. Remaining Useful Life of the North Valmy Units

NDEP's Four-Factor Analysis assumes a remaining useful life ("RUL") of 30 years beyond the control installation date for the North Valmy units.[48] This 30-year RUL is consistent with EPA's Control Cost Manual,[49] and is a reasonable assumption for all three control technologies considered. NV Energy characterizes this assumption as conservative, as a 30-year RUL runs beyond the planned North Valmy unit retirement dates in 2049.[50] Nevada law calls for NV Energy to reach net zero carbon emissions by 2050.[51] However, the 2049 North Valmy unit retirement dates are not federally enforceable, so it was appropriate for NDEP to use the 30-year RUL in the Four-Factor Analysis rather than shortening the RUL to match the planned retirement dates.

4. North Valmy NOx Baseline Is Unsupported.

NDEP's SIP Revision relies on NV Energy's calculation of the NOx emissions of the North Valmy units to conduct its four-factor analyses. NDEP states that these figures project what the NOx emissions of these units would have been from 2016 through 2018, had they been powered by natural gas, using Low NOx Burners ("LNBs").[52] NDEP indicates that the estimated NOx emissions for Unit 1 is 344.6 tons/yr and for Unit 2 is 457.8 tons/yr.[53] NDEP states that 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.[54]

However, neither NDEP's Four-Factor Analysis nor NV Energy's underlying analysis explain or document how these figures were actually calculated. Multiplying NDEP's NOx emission rate of 0.137 lbs/MMBtu by the 2016-2018 average heat inputs presented in Table 1 of NDEP's Four-Factor Analysis results in values of 327 tons per year for Unit 1 and 433 tons per

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[45] 2025 SIP Supplement, Appendix E.1 at 2, 8.
[46] *Id*.
[47] *Id*. at 2.
[48] 2025 SIP Supplement at 2-6.
[49] EPA, Air Pollution Control Cost Manual [hereinafter "EPA Control Cost Manual"], Section 2, Chapter 3 – Permanent Total Enclosures (PTEs) at 3-33 (Sept. 2002), https://www.epa.gov/sites/default/files/2020-07/documents/c_allchs.pdf.
[50] 2025 SIP Supplement, Appendix B at 14.
[51] Nev. Rev. Stat. §§ 704.741, 704.7820.
[52] 2025 SIP Supplement at 2-2 to 2-3, Tbl. 2-2.
[53] *Id*. at 2-3 (Tbl. 2-2).
[54] *Id*. at 2-2 to 2-3.

year for Unit 2.[55] Each of these figures are about 5% lower than NDEP's figures. Mr. Kordzi's report concludes that this suggests NDEP and NV Energy have used an additional unidentified factor, perhaps relating to the differing expected heat rates following the conversion to natural gas.[56] NDEP must document this calculation and explain how it obtained the resulting figures.

5. NDEP's North Valmy Electricity Generation Projections Are Unreasonably Low and Not Representative.

NDEP's projected electrical output figure for North Valmy Units 1 and 2 is not a reasonable projection for those units. NDEP's calculation of the NOx baseline wrongly accepts NV Energy's contention that the average electrical output of North Valmy from 2016 through 2018 should be used to establish the NOx baseline. For example, Figure 1 of NV Energy's Four-Factor Analysis uses a 2016 through 2018 average value of 1,042,000 MWh/yr to represent the future electrical output for the North Valmy units.[57] However, Mr. Kordzi's report finds that this value is inaccurate, and was exceeded in all but one year between 2016 and 2024.[58]

Table 1. Historical North Valmy Electrical Output (MWh/yr)

Year	Unit 1	Unit 2	Total
2016	557,937	535,465	1,093,401
2017	353,877	403,652	757,529
2018	677,681	977,502	1,655,183
2019	1,202,709	709,566	1,912,276
2020	442,284	642,581	1,084,865
2021	621,369	1,177,825	1,799,194
2022	709,221	943,747	1,652,968
2023	536,809	670,476	1,207,285
2024	674,484	756,283	1,430,767

Table 1 shows the total MWh/yr for Units 1 and 2 using data from EPA's CAMPD site. Even if NDEP or NV Energy had demonstrated that an average from the years 2016 to 2018 was appropriate for assuming future usage, which they did not, the actual average is 1,168,705 MWh.[59] Regardless, NDEP's value of 1,042,000 MWh was exceeded every year since 2016 with the exception of 2017. NDEP's chosen figure does not represent a reasonable projection of the electricity production of North Valmy Units 1 and 2. NDEP must select a higher, more reasonable electrical output figure, or else impose a federally enforceable requirement that its chosen output figure cannot be exceeded.

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[55] 2025 Kordzi Report at 3.
[56] *Id.*
[57] 2025 SIP Supplement, Appendix B at 4.
[58] 2025 Kordzi Report at 3-4.
[59] *Id*. at 4.

6. NDEP's North Valmy NOx Inlet Rate Is Unsupported.

NDEP's NOx baseline calculations for North Valmy use an unsupported value for the expected NOx emission rate following the conversion to natural gas, a key figure in NDEP's Four-Factor Analysis. NDEP accepts NV Energy's proposed 0.137 lbs/MMBtu value, which NV Energy states is derived from the AP-42 document.[60] NDEP does not provide any data to support its chosen value, and the SIP Revision does not explain why this value would be representative for the North Valmy units.[61]

Actual data from 1995 (the approximate vintage of the AP-42 data) through 2024 indicates that there are many examples of natural gas wall-fired boilers fitted with low NOx burners, as detailed in Mr. Kordzi's report.[62] A review of data from EPA's Clean Air Markets Program Data ("CAMPD") site for EGUs from 1995 through 2024 shows that there are 39 unique instances in which a natural gas wall-fired boiler with only LNBs for NOx control exceeded NDEP's assumed NOx rate of 0.137 lbs/MMBtu and 39 unique instances below that level. NDEP should have used real-world, high quality data from representative boilers rather than accepting the low quality AP-42 emission factor used by NV Energy.

There is a wide range in the annual average NOx rates in this data, and NDEP does not explain why its chosen value is appropriate for the North Valmy units. Given the absence of any site-specific data, NDEP should have placed the burden of proof on NV Energy to provide well-documented value for the NOx inlet. Mr. Kordzi's report concludes that it is more reasonable to set the NOx inlet value to 0.20 lbs/MMBtu, slightly above the average annual NOx value of these data (0.160 lbs/MMBtu).[63]

7. NDEP's SCR and SNCR Efficiency Assumptions for North Valmy Are Unreasonably Low.

NDEP's cost-effectiveness analysis for emissions controls at North Valmy also uses unreasonably low efficiency assumptions for SCR and SNCR. NDEP's SIP revision does not explain why NDEP selected its chosen efficiency values in the four-factor determination.[64] NV Energy also does not justify or discuss how it selected these values in its Four-Factor Analysis. The only available information concerning these values appears in NV Energy's undocumented figures for the SCR and SNCR NOx outlets in its cost models:[65]

[60] 2025 SIP Supplement at 2-3.
[61] *See* 2025 Kordzi Report at 4.
[62] 2025 Kordzi Report at 4-7 (Tbl 2).
[63] *Id*. at 7.
[64] *Id*. at 8.
[65] *Id*.

Table 2. NV Energy's Undocumented SNCR and SCR NOx Outlets

Unit	SNCR (lbs/MMBtu	SCR (lbs/MMBtu)
1	0.1029	0.0300
2	0.1029	0.0300

A NOx outlet of 0.1029 lbs/MMBtu corresponds to only a 25% SNCR efficiency from a NOx inlet of 0.137 lbs/MMBtu.[66] NDEP and NV Energy do not provide any documentation to support their chosen values. Mr. Korzi's report therefore surveyed the best-performing SNCR and SCR systems for natural gas wall-fired boilers at other plants.

For SNCR, Mr. Kordzi surveyed systems with annual NOx averages below NDEP's assumed NOx outlet of 0.1029 lbs/MMBtu, using data from EPA's CAMPD site for EGUs from 1995 through 2024.[67] Mr. Kordzi found 11 instances where the annual average NOx value for a natural gas wall-fired boiler with SNCR for NOx control is below NDEP's assumed NOx rate of 0.1029 lbs/MMBtu. Moreover, Mr. Kordzi found only two instances since 1995 in which SNCR systems installed on gas wall-fired boilers exceeded an annual average of 0.1029 lbs/MMBtu. Therefore, NDEP must either assume a lower, more conservative value for the SNCR NOx outlet, or demonstrate why the North Valmy units cannot achieve a similar level of performance as the higher-performing EGUs identified in Mr. Kordzi's report.

For SCR, Mr. Kordzi surveyed SCR systems installed on gas wall-fired boilers with annual NOx averages below NDEP's assumed NOx outlet of 0.0300 lbs/MMBtu, again using data from EPA's CAMPD site for EGUs from 1995 through 2024.[68] Mr. Kordzi found 37 instances where the annual NOx average value for a natural gas wall-fired boiler with SCR for NOx control are below NDEP's assumed NOx rate of 0.0300 lbs/MMBtu. Mr. Kordzi found only three instances since 1995 in which SCR systems installed on gas wall-fired boilers exceeded an annual average of 0.0300 lbs/MMBtu. Accordingly, NDEP must either assume a lower, more conservative value for the SCR NOx outlet, or demonstrate why the North Valmy units cannot achieve a comparable level of performance to the EGUs identified by Mr. Kordzi.

8. NDEP's Cost-Effectiveness Analysis for SNCR at North Valmy Is Riddled with Inaccuracies.

NV Energy's Four-Factor Analysis uses EPA's Control Cost Manual to obtain input values for its cost-effectiveness evaluation of SNCR, but does not use the latest version.[69] Moreover, as discussed below, NV Energy improperly selected a number of key inputs, such as the NOx baseline and the efficiencies that modern SNCR systems are capable of achieving. These flawed inputs include annual MWh Output, net plant heat rate, Inlet and Outlet SNCR NOx Rates, normalized Stoichiometric Ratio, concentration and cost of reagent, Chemical

[66] 2025 Kordzi Report at 8.
[67] *Id.* at 8-9, Tbl. 4.
[68] *Id*. at 9-11, Tbl. 5.
[69] *See id.* at 11.

Engineering Plant Cost Index, cost of electricity, and fuel cost. Mr. Kordzi's report identifies each of these errors and improperly selected inputs, and replaces them with corrected values.

a. NDEP's Estimated Annual MWh Output Is Too Low.

NDEP's Four-Factor Analysis underestimates the annual MWh output of North Valmy Units 1 and 2. As discussed above, NDEP wrongly accepted NV Energy's claim that the future electrical output for those units can be represented by a 2016 through 2018 average value of 1,042,000 MWh/yr, including 466,437 MWh at Unit 1 and 575,835 MWh at Unit 2.[70] This parameter has a significant impact in the cost-effectiveness calculation, as it is used to calculate the capacity factors of each unit. As the annual MWh output decreases, the cost per ton increases and the cost-effectiveness of controls worsens. NDEP's use of inaccurately low values, which fall below the values reported to EPA and which have been regularly exceeded, results in NDEP understating the cost-effectiveness of controls. Mr. Kordzi's report instead uses more representative values of 596,833 MWh and 838,182 MWh for Units 1 and 2, which correspond to averages from the last five years.[71]

b. NDEP's Net Plant Heat Rate Is Too High.

NDEP's Four-Factor Analysis uses an inappropriately high value for the Net Plant Heat Rate ("NPHR"), which is the heat needed in order to produce electricity in units of MMBtu/MW. NDEP relies on NV Energy's Four Factor Analysis, which uses values of 10.765 MMBtu/MW and 11.584 MMBtu/MW for North Valmy Units 1 and 2, respectively.[72] These are typical values for coal-fired and fuel-oil boilers (likely calculated when the Valmy units were burning coal), but they are not appropriate for most gas-fired boilers, as Mr. Kordzi's report explains.[73] EPA's SNCR and SCR Control Cost Manual spreadsheets use the following default values:

Table 3. Control Cost Manual Default Values for NPHR

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

NDEP and NV Energy do not provide any documentation to justify their chosen NPHR values for the North Valmy units after their conversion to gas, which are unusually high for gas-fired boilers. Mr. Kordzi's report concludes that NDEP should have used the default NPHR value of 8.2 MMBtu/MW for gas-fired boilers.[74] Mr. Kordzi's report notes that "[t]he NPHR has a significant impact on the cost-effectiveness calculation and lowering these values to 8.2 MMBtu/MW significantly worsened the cost-effectiveness" of emissions controls.[75]

70 2025 Kordzi Report at 11.
71 *Id.*
72 2025 SIP Supplement, Appendix B, Sub-Appendix A (PDF pp. 159, 174).
73 2025 Kordzi Report at 11-12.
74 *Id.* at 12.
75 *Id.*

c. NDEP's Inlet and Outlet SNCR NOx Rates Are Unreasonable and Unsupported.

As discussed above, NDEP's methodology for selecting its SNCR NOx inlets and outlets is not documented, and the resulting values do not reasonably correspond to real-world examples. Mr. Kordzi's report therefore rejects NDEP's approach, and concludes that a reasonably conservative value for the NOx inlet would have been 0.200 lbs/MMBtu.[76] Because of the inherent uncertainty in SNCR cost-effectiveness analysis resulting from site-specific design considerations, Mr. Kordzi notes that it is appropriate to assess SNCR cost-effectiveness using a range of efficiencies, and concludes that NDEP should have selected a reasonable range of NOx outlet values, like those shown in Table 7.[77]

Table 4. North Valmy SNCR NOx Inlets and Outlets

NOx Inlet (lbs/MMBtu)	NOx Outlet (lbs/MMBtu)	SNCR Efficiency Range (%)
0.200	0.120	40
0.200	0.100	50

Outlet NOx values of 0.100 or 0.120 are well above those reported for gas wall-fired boilers, as discussed above, and are thus conservative. In addition, the efficiency range of 40 – 50% is well within the range reported in EPA's Control Cost Manual for ammonia-based gas and oil-fired industrial boilers.[78] NDEP should have used reasonably conservative values like those identified in Mr. Kordzi's analysis.

d. NDEP's Normalized Stoichiometric Ratio Is Unsupported.

NDEP does not provide support for its chosen Normalized Stoichiometric Ratio ("NSR") value. NV Energy does not explain why it chose an NSR value of 0.50. EPA's Control Cost Manual describes this parameter as follows:[79]

> The normalized stoichiometric ratio (NSR) defines the amount of reagent needed to achieve the targeted NOx reduction. Theoretically, based on reaction equations 1.1(a) and (b) and 1.2(a) and (b), two moles of NO can be removed with one mole of urea or two moles of ammonia and one mole of NO_2 requires one mole of urea and two moles of ammonia. Since NOx is mostly comprised of NO (approximately 95%), the theoretical NSR for NOx is close to one mole of ammonia per mole of NO x and 0.5 moles of urea per mole of NOx . In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of NO x reduction. This is due to the complexity

[76] *Id.*
[77] *Id.*
[78] EPA Control Cost Manual, Section 4, Chapter 1 - Selective Noncatalytic Reduction at 1-2 (revised Apr. 25, 2019), https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[79] *Id.* at 1-17.

of the actual chemical reactions involving NO x and injected reagent and mixing limitations between reagent and flue gas (rate kinetics). Typical NSR values are between 0.5 and 3 moles of ammonia per mole of NOx. Because capital and operating costs depend on the quantity of reagent consumed, determining the appropriate NSR is critical.

The Control Cost Manual explains how this parameter should be calculated, which depends on the NOx inlet, the SNCR efficiency, and the corresponding NOx outlet. Mr. Kordzi's report utilizes EPA's Control Cost Manual spreadsheet to incorporate these calculations.[80] Mr. Kordzi concludes that, given NV Energy's chosen NOx inlet of 0.137 lbs/MMBtu and its NOx outlet of 0.1029 lbs/MMBtu (equating to a 25% SNCR efficiency), the NSR should have been 1.78, applying EPA's methodology.[81] Increasing the NSR has the effect of worsening the cost-effectiveness of SNCR, since it means the SNCR system is using more reagent. Mr. Kordzi's report uses EPA's methodology to calculate the NSR in its SNCR cost-efficiency calculations.

e. NDEP Uses Incorrect Values for the Concentration and Cost of Reagent.

NDEP's chosen value for the concentration of reagent is too low, while its chosen value for the cost of reagent is too high. NV Energy's Four-Factor Analysis assumes a 19% concentration of ammonia at a cost of $0.95/gallon.[82] NV Energy states that it chose this concentration because "[f]acilities 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%."[83] Mr. Kordzi's report concludes that this second sentence of this statement is misleading, to the extent it gives the impression that NV Energy could not use concentrations of ammonia higher than 19%.[84] It is common for SNCR and SCR systems to utilize 29% ammonia, and that is the default concentration for EPA's Control Cost Manual SNCR and SCR spreadsheets when ammonia is selected as the reagent. Nothing in Nevada law prohibits NV Energy from storing a 29% concentration of ammonia onsite. NV Energy would simply have to undergo additional permitting under Nevada's Chemical Accident Prevention Program.[85] Mr. Kordzi's report therefore assumes a 29% ammonia concentration in its SNCR and SCR analyses.

Mr. Kordzi also finds that NDEP's chosen ammonia price is excessive.[86] NPS's analysis bolsters Mr. Kordzi's conclusion, noting that NV Energy's reagent cost number is "exceptionally

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[80] 2025 Kordzi Report at 13.
[81] *Id.*
[82] 2025 SIP Supplement, Appendix B, Sub-Appendix A (PDF p. 160).
[83] 2025 SIP Supplement, Appendix B at 18.
[84] 2025 Kordzi Report at 13.
[85] *See* NDEP, Chemical Accident Prevention Program (CAPP): Regulated Substance (last visited Mar. 27, 2025), https://ndep.nv.gov/air/chemical-accident-prevention/regulated-substance.
[86] 2025 Kordzi Report at 14.

high."[87] EPA's 2019 update of its Control Cost model assumes as a default that ammonia will be used at a concentration of 29% and a cost of \$0.293/gallon.[88] That cost is based on the average price of ammonia of \$270 per ton indicated in the 2017 U.S. Geological Survey Minerals Commodity Summary for Nitrogen.[89] NV Energy has not provided any documentation to support its chosen price of ammonia. The average price of ammonia in the 2024 U.S. Geological Survey Minerals Commodity Summary for Nitrogen was \$440 per ton.[90] Because NDEP has not provided documentation to support its chosen values, Mr. Kordzi concludes that ammonia should be assumed to be stored onsite at a concentration of 29% and at a cost of \$0.477/gallon.[91] This adjustment improves the cost-effectiveness of SNCR and SCR, since the cost of the ammonia reagent is lower.

f. NDEP's Chemical Engineering Plant Cost Index Value Is Too High.

Mr. Kordzi's report concludes that NDEP's Four-Factor Analysis uses an improperly high value for the Chemical Engineering Plant Cost Index ("CEPCI").[92] EPA's Control Cost Manual SNCR Spreadsheet uses the annual value of the CEPCI to escalate 2016 dollars (the dollar year of its internal cost algorithms) to current dollars. NV Energy used a value of 824.5 for the CEPCI, noting that is a "Mar-23" value, but improperly listed it as a 2024 value.[93] As of the date of these comments, the annual CEPCI value for 2024 has not been published.[94] Mr. Kordzi's report therefore uses the 2023 annual value for the CEPCI index, 797.9, which is the latest annual value available.[95] This adjustment improves the cost-effectiveness of SNCR and SCR since the capital cost is lower.

g. NDEP's Cost of Electricity Value Is Unsupported.

NDEP and NV Energy use a cost of electricity of \$0.0754/kWh.[96] Neither NDEP nor NV Energy provide any documentation for this value. Mr. Kordzi's report explains that this cost is supposed to represent the North Valmy plant's actual cost to produce electricity, after having

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87 2025 SIP Supplement, Appendix E.1 at 4, n.3.
88 2025 Kordzi Report at 14.
89 *See* National Minerals Information Center, Statistics and information on the worldwide supply of, demand for, and flow of the mineral commodity nitrogen: 2017 Mineral Commodity Summary for Nitrogen (last visited Mar. 27, 2025), available at https://www.usgs.gov/centers/national-minerals-information-center/nitrogen-statistics-and-information.
90 *See* U.S. Geologic Survey, Mineral Commodity Summaries, January 2025: Nitrogen—Fixed (Ammonia), https://pubs.usgs.gov/periodicals/mcs2025/mcs2025-nitrogen.pdf.
91 2025 Kordzi Report at 13-14.
92 *Id*. at 14.
93 *See* 2025 SIP Supplement, Appendix B, Sub-Appendix A (PDF p. 160); 2025 Kordzi Report at 14.
94 2025 Kordzi Report at 14.
95 *Id.*
96 2025 SIP Supplement, Appendix B, Sub-Appendix A (PDF p. 160, 168, 175, 183).

switched to natural gas, and not a wholesale or retail value.[97] EPA's Control Cost Manual SNCR Spreadsheet uses the 2017 annual average cost of $0.0361/kWh, based on information previously published by the U.S. Energy Information Agency ("EIA"). However, it appears that the EIA has stopped publishing this information, and so newer information cannot be obtained from the cited website. Mr. Kordzi's report therefore retains the NV Energy value, but NDEP must require documentation to support this figure.[98]

h. NDEP's Fuel Cost Is Unsupported.

NDEP and NV Energy use a fuel cost of $1.66/MMBtu in the Four-Factor Analysis without any documentation.[99] This value is supposed to represent the cost of fuel at North Valmy after the plant is converted to natural gas. Absent documentation, EPA's Control Cost Manual SNCR Spreadsheet uses the latest average value as reported by the EIA.[100] Mr. Kordzi's report therefore uses the latest value for natural gas, $3.36/MMBtu, which is from 2023.[101] This change has the effect of slightly worsening the cost-effectiveness of controls due to the increased fuel cost.

9. NDEP Underestimates the Cost-Effectiveness of SNCR at North Valmy.

As discussed above, NDEP's Four-Factor Analysis contains many errors that undermine the accuracy of its calculations regarding the cost-effectiveness of SNCR at North Valmy. Mr. Kordzi's report explains that, once these flaws are corrected, the resulting calculation shows that the cost per ton of SNCR is significantly lower, and SNCR is significantly more cost-effective than NDEP calculated.[102] This is the case for both North Valmy units, and this conclusion holds true regardless of whether the SNCR efficiency is set at 40% or 50%, as shown below.

Table 5. Revised SNCR Cost-Effectiveness Values for North Valmy Unit 1

North Valmy Unit 1	SNCR @40% efficiency	SNCR @50% efficiency	Units
Fuel type	Natural Gas	Natural Gas	
Retrofit factor	1	1	
MW rating	237	237	MW
HHV	1,020	1,020	Btu/lb
Annual MWh output	596,833	596,833	MWh

[97] 2025 Kordzi Report at 14.
[98] *Id.*
[99] 2025 SIP Supplement, Appendix B, Sub-Appendix A (PDF p. 160, 175).
[100] *See* EIA, Electric Power Annual, Table 7.4: Weighted average cost of fossil fuels for the electric power industry (Oct. 17, 2024), available at https://www.eia.gov/electricity/annual/; 2025 Kordzi Report at 14-15.
[101] 2025 Kordzi Report at 15.
[102] *Id.* at 14-17.

Net plant heat input rate ("NPHR")	8.2	8.2	MMBtu/MW
Desired SNCR efficiency	**40**	**50**	Percent
NOx inlet	0.2	0.2	lb/MMBtu
NOx outlet	0.12	0.1	lb/MMBtu
Reagent	Ammonia	Ammonia	
Plant elevation	4,455	4,455	feet
Desired dollar-year	2023	2023	
Interest rate	6.95	6.95	Percent
Equipment life	30	30	years
Total Capital Investment ("TCI")	$7,569,961	$7,693,207	
Direct Annual Costs ("DAC")	$303,880	$353,312	
Indirect Annual Costs ("IDAC")	$610,517	$620,457	
Total Annual Costs ("TAC") = DAC + IDAC	$914,398	$973,769	
NOx removed	196	245	tons/year
Cost-effectiveness	**$4,671**	**$3,979**	**$/ton**

Table 6. Revised SNCR Cost-Effectiveness Values for North Valmy Unit 2

North Valmy Unit 2	SNCR @40% efficiency	SNCR @50% efficiency	Units
Fuel type	Natural Gas	Natural Gas	
Retrofit factor	1	1	
MW rating	264	264	MW
HHV	1,020	1,020	Btu/lb
Annual MWh output	838,182	838,182	MWh
Net plant heat input rate ("NPHR")	8.2	8.2	MMBtu/MW
Desired SNCR efficiency	**40**	**50**	Percent
NOx inlet	0.2	0.2	lb/MMBtu
NOx outlet	0.12	0.1	lb/MMBtu
Reagent	Ammonia	Ammonia	
Plant elevation	4,455	4,455	feet
Desired dollar-year	2023	2023	
Interest rate	6.95	6.95	Percent
Equipment life	30	30	years
Total Capital Investment ("TCI")	$7,936,277	$8,065,653	
Direct Annual Costs ("DAC")	$386,342	$455,107	

Indirect Annual Costs ("IDAC")	$640,061	$650,495	
Total Annual Costs ("TAC") = DAC + IDAC	$1,026,402	$1,105,601	
NOx removed	275	344	tons/year
Cost-effectiveness	**$3,733**	**$3,217**	**$/ton**

By contrast, NDEP's proposed SIP supplement calculates the SNCR average cost-effectiveness values to be $9,740 per ton for North Valmy Unit 1 and $8,018 per ton for North Valmy Unit 2.[103] Mr. Kordzi's revised cost-effectiveness calculations for these units, which use more supportable inputs and a SNCR efficiency range of 40 to 50%, result in SNCR average costs per ton of $3,979 to $4,671 per ton for Unit 1 and $3,217 to $3,733 per ton for Unit 2, roughly half of those estimated by NDEP.[104] This indicates that SNCR is significantly more cost-effective than NDEP calculated.

10. NDEP's Cost-Effectiveness Analysis for SCR at North Valmy Is Also Deeply Flawed.

NDEP's analysis of the cost-effectiveness of SCR at North Valmy Units 1 and 2 suffers from several of the same errors that impact the SNCR analysis, plus several additional flaws that are specific to SCR. As explained above, NV Energy improperly selected a number of key inputs, such as the NOx baseline and the efficiencies that modern SCR and SNCR systems are capable of achieving. Mr. Kordzi's report identifies several other flaws in NDEP's and NV Energy's SCR analysis, which involve misuse of EPA's SCR Control Cost Manual cost-effectiveness spreadsheets, lack of documentation, or improperly selected input values.[105]

a. NDEP's Inlet and Outlet SCR NOx Rates Are Unsupported.

As discussed above, NDEP does not document its methodology for selecting its SCR NOx inlets and outlets, and the resulting values are not representative in comparison to many real-world examples. As with SNCR, Mr. Kordzi's report selected a reasonably conservative NOx inlet value of 0.200 lbs/MMBtu for SCR.[106] For the NOx outlet, considering that many SCR systems installed on gas wall-fired boilers are capable of achieving average annual NOx emission rates below 0.01 lbs/MMBtu, Mr. Kordzi's report chose that figure.[107]

b. NDEP's Catalyst Life Value for SCR Is Unreasonably Low.

NDEP's Four-Factor Analysis uses an incorrect catalyst life value in its cost-effectiveness calculations for SCR. NV Energy assumed a 24,000 hour catalyst life in its SCR cost-effectiveness calculations.[108] Mr. Kordzi's report explains that, while a 24,000 hour catalyst life is appropriate for hot-side coal-fired SCR installations, catalyst life for a gas-fired SCR

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[103] 2025 SIP Supplement at 2-4, 2-5 (Tbl. 2-3).
[104] 2025 Kordzi Report at 14-17.
[105] *Id.* at 18.
[106] *Id.*
[107] *Id.*
[108] 2025 SIP Supplement, Appendix B, Sub-Appendix A (PDF p. 168).

system is considerably longer.[109] EPA's Control Cost Manual states that "[f]or oil- and gas-fired units, the SCR catalyst life is assumed to be 40,000 hours, and the catalyst life for some gas-fired units has been reported to be up to 60,000 hours."[110] Mr. Kordzi's report explains that NDEP should have selected a catalyst life of 40,000 hours.[111]

NDEP and NV Energy also do not provide documentation to support their selected catalyst cost. NV Energy uses a catalyst cost of $254.85/ft^3$, without any documentation.[112] This is higher than EPA's default value of $227/ft^3$, which was based on EPA's 2018 IPM Power Sector Modeling Platform v6, May 2018. However a 2023 version of that same documentation now indicates that catalyst cost has risen to $9,000/m^3$ ($254.85), based on 2021 dollars.[113] This is consistent with NV Energy's figure, and Mr. Kordzi's report therefore uses NV Energy's catalyst cost value.[114]

11. NDEP underestimates the cost-effectiveness of SCR at North Valmy.

As discussed above, NDEP's Four-Factor Analysis contains many errors that undermine the accuracy of its calculations regarding the cost-effectiveness of SCR at North Valmy. Mr. Kordzi's report explains that, once these flaws are corrected, the resulting calculation shows that the cost per ton of SCR is significantly lower, and SCR is significantly more cost-effective than NDEP calculated for both North Valmy units, as shown in the tables below.[115]

Table 7. Revised SCR Cost-Effectiveness Values for North Valmy Unit 1

Fuel type	Natural Gas	
Retrofit factor	1	
MW rating	237	MW
HHV	1,020	Btu/lb
Annual MWh output	596,833	MWh
Total System Capacity Factor ("CF_{total}")	0.287	
Net plant heat input rate ("NPHR")	8.2	MMBtu/MW
NOx inlet	0.2	lb/MMBtu

[109] 2025 Kordzi Report at 18.
[110] EPA Control Cost Manual, Section 4, Chapter 2 - Selective Catalytic Reduction at PDF p. 77 (revised June 12, 2019), https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution [hereinafter "EPA Control Cost Manual: SCR"].
[111] 2025 Kordzi Report at 18.
[112] 2025 SIP Supplement, Appendix B, Sub-Appendix A (PDF p. 168).
[113] *See* EPA, Documentation for Post-IRA 2022 Reference Case: EPA's Power Sector Modeling Platform v6 Using IPM, Attachment 5-4: SCR Cost Methodology for Oil-Gas-Fired Boilers (Feb. 2023), https://www.epa.gov/power-sector-modeling/documentation-post-ira-2022-reference-case.
[114] 2025 Kordzi Report at 18.
[115] *Id*. at 18-19.

NOx outlet	0.01	lb/MMBtu
Reagent	Ammonia	
Plant elevation	4,455	feet
Desired dollar-year	2023	
Interest rate	6.95	Percent
Equipment life	30	years
Total Capital Investment ("TCI")	$0	
Direct Annual Costs ("DAC")	$601,538	
Indirect Annual Costs ("IDAC")	$2,686,436	
Total Annual Costs ("TAC") = DAC + IDAC	$3,287,974	
NOx removed	465	tons/year
Cost-effectiveness	**$7,072**	**$/ton**

Table 8. Revised SCR Cost-Effectiveness Values for North Valmy Unit 2

Fuel type	Natural Gas	
Retrofit factor	1	
MW rating	264	MW
HHV	1,020	Btu/lb
Annual MWh output	838,182	MWh
Total System Capacity Factor ("CF_{total}")	0.362	
Net plant heat input rate ("NPHR")	8.2	MMBtu/MW
NOx inlet	0.2	lb/MMBtu
NOx outlet	0.01	lb/MMBtu
Reagent	Ammonia	
Plant elevation	4,455	feet
Desired dollar-year	2023	
Interest rate	6.95	Percent
Equipment life	30	years
Total Capital Investment ("TCI")	$0	
Direct Annual Costs ("DAC")	$753,441	
Indirect Annual Costs ("IDAC")	$2,881,359	
Total Annual Costs ("TAC") = DAC + IDAC	$3,634,800	
NOx removed	653	tons/year
Cost-effectiveness	**$5,567**	**$/ton**

NDEP's proposed SIP supplement calculates the SCR cost-effectiveness values to be $13,122 per ton for North Valmy Unit 1 and $10,903 per ton for Unit 2, respectively.[116] Mr. Kordzi's revised cost-effectiveness calculations for these units, which use better-supported input values and a conservative NOx outlet rate of 0.01 lbs/MMBtu, result in costs per ton of $7,072 for Unit 1 and $5,567 for Unit 2, almost half of the values proposed by NDEP.[117] This indicates that SCR is much more cost-effective than NDEP calculated, and well below Nevada's $10,000 per ton cost-effectiveness threshold.

The NPS review of NDEP's revised SIP affirms Mr. Kordzi's overall conclusion, finding that SCR is cost-effective for North Valmy Units 1 and 2.[118] NPS finds that SCR can reduce North Valmy's NOx emissions by almost 800 tons per year at an annual cost of $7.2 million, for a cost-effectiveness value of under $10,000 per ton for both units.[119] Specifically, NPS calculates that the cost-effectiveness of SCR at Unit 1 is $9,690 per ton, and that the cost-effectiveness of SCR at Unit 2 is $8,745 per ton.[120] NPS explained that its SCR cost estimates for North Valmy are lower than those provided by NV Energy because the NPS analysis (1) used higher utilization data to reflect anticipated future utilization after Idaho Power Company exits the plant, (2) used higher Heat Input values, (3) assumed that SCR could achieve a slightly lower emission rate based on 2023 CAMPD data, (4) used the 2023 (instead of 2024) CEPCI, and (5) used the 2023 cost of ammonia reagent.[121] While NPS's estimated SCR cost-effectiveness values differ from Mr. Kordzi's calculations, they reinforce the same general conclusion that SCR is cost-effective for both North Valmy units.

12. NDEP Should Require SCR as the Reasonable Progress Measure at North Valmy.

Both Mr. Kordzi's report and the NPS analysis demonstrate that SCR is a cost-effective control measure for both North Valmy units, and well below Nevada's $10,000 per ton threshold, as discussed above. SCR is also the control measure that would achieve the greatest NOx reductions at North Valmy. NDEP estimates that SCR would reduce NOx emissions by 269.3 tons per year at Unit 1 and 357.7 tons per year at Unit 2, more than triple the NOx reductions that SNCR would achieve.[122] However, NDEP's Four-Factor Analysis understates the emissions reductions that SCR would achieve, due to the errors discussed above. Mr. Kordzi's analysis shows that SCR would reduce more NOx emissions than NDEP calculates, and significantly more than SNCR. SCR would reduce NOx emissions by 465 tons per year at Unit 1, and 653 tons per year at Unit 2.[123] In total, selecting SCR would advance the regional haze program's purpose by reducing NOx emissions by 1,118 tons per year. By comparison, Mr.

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[116] 2025 SIP Supplement at 2-5.
[117] 2025 Kordzi Report at 19-20.
[118] 2025 SIP Supplement, Appendix E.1 at 2, 8.
[119] *Id.*, Appendix E.1 at 7.
[120] *Id.*, Appendix E.1 at 6.
[121] *Id.*, Appendix E.1 at 8.
[122] 2025 SIP Supplement at 2-5.
[123] 2025 Kordzi Report at 19-20.

Kordzi's report indicates that SNCR would only reduce between 196 and 245 tons per year at Unit 1, and between 275 and 344 tons per year at Unit 2.[124]

Given that SCR meets NDEP's cost-effectiveness threshold and would maximize NOx reductions, NDEP's decision not to select SCR as a reasonable progress measure is unreasonable. As EPA has explained, "[w]hen the outcome of a four-factor analysis is a new measure, that measure is needed to remedy existing visibility impairment and is necessary to make reasonable progress."[125] NDEP should not reject practical, cost-effective measures that will maximize reductions in visibility-impairing pollution.[126] The Conservation Organizations therefore recommend that NDEP require SCR as a reasonable progress measure for both North Valmy units.

NPS likewise recommends that because SCR is cost-effective and would reduce significantly more NOx emissions per year than SNCR, NDEP should have required SCR as the reasonable progress measure for both North Valmy units.[127] NPS also recommends that if NDEP determines that SCR is not cost-effective due to limited utilization, NDEP should include a federally-enforceable limit on individual unit utilization at North Valmy.[128] The Conservation Organizations support NPS's recommendation that NDEP impose an enforceable limit on the North Valmy units' utilization if NDEP rejects SCR for this reason.

D. The Tracy Plant Four-Factor Analysis Is Deficient.

1. Background

Tracy Generating Station is a six-unit 885 MW gas-fired power plant operated by NV Energy. Tracy consists of Unit 3, a conventional pipeline gas-fired steam boiler, Units 5 and 6 (also referred to as Clark Mountain 3 and 4), pipeline gas and distillate-fired combustion turbines, and Units 7, 32, and 33 (also referred to as Unit 4 Piñon Pine, Unit 8, and Unit 9), pipeline gas-fired combined-cycle units. Tracy causes significant visibility-impairing pollution in the state of Nevada, including in the Class I Desolation Wilderness area located just 81 kilometers west in El Dorado County, California.[129]

In its 2022 draft SIP revision, NDEP relied on existing controls for Units 3, 5, 6, 32, and 33.[130] NDEP noted that Units 5 and 6 had low emissions and low utilization and therefore

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[124] *Id*. at 15-17.
[125] Memorandum from Peter Tsirigotis, Dir., EPA, to Reg'l Air Dirs., Regions 1-10 at 8 (July 8, 2021), https://www.epa.gov/visibility/clarifications-regarding-regional-haze-state-implementation-plans-second-implementation [hereinafter "Clarification Memo"] (attached as Ex. 17); *see also* 2019 Guidance at 40 n.71 ("If the measure is not rejected as unreasonable based on the cost of compliance alone, it would be determined to be necessary for reasonable progress unless one or more of the other three factors makes it unreasonable.").
[126] *See* 82 Fed. Reg. at 3088; Clarification Memo at 7.
[127] 2025 SIP Supplement, Appendix E.1 at 2, 8.
[128] *Id*.
[129] 2025 SIP Supplement at 3-1.
[130] 2022 SIP Revision at 5-18.

required no additional reasonable progress measures.[131] NDEP further determined that existing controls were sufficient for Units 32 and 33. The Conservation Organizations explained in July 2022 comments that NDEP had to ensure that Units 5 and 6 ongoing operations reflect low emissions and low utilization in order to comply with the goals of the regional haze program.[132] For Unit 3, NDEP evaluated SCR and SNCR but found both controls exceeding the $10,000-per-ton threshold for cost-effectiveness and subsequently required no additional reasonable progress measures.[133] The Conservation Organizations explained that EPA's BART determination *already* required NV Energy to operate SNCR at Unit 3 under the statutory requirements of the Clean Air Act, that NV Energy failed to comply, and that NDEP failed to consider cost-effective options for ensuring that Unit 3's NOx emissions reflect SNCR.[134]

The 2025 SIP Supplement continues to rely on existing controls at Units 3, 5, 6, 32, and 33 to make reasonable progress.[135] It relies on the 2022 SIP Revision's faulty determination that no additional controls are cost-effective or necessary to make reasonable progress at Unit 3.[136]

Prior to 2024, Tracy Unit 4 Piñon Pine (also referred to as Unit 7) was slated to retire by December 31, 2031.[137] As a result, in its 2022 draft SIP Revision, NDEP identified Unit 4 Piñon Pine retirement as a reasonable progress measure in lieu of other controls.[138] The Conservation Organizations explained that even with a planned 2031 retirement for Unit 4 Piñon Pine, NDEP should have selected SCR as a cost-effective reasonable progress measure to reduce haze pollution before the end of the second implementation period in 2028 or alternatively require NV Energy to retire Unit 4 Piñon Pine by December 31, 2028 so that the NOx emissions reductions from reasonable progress measures accrue before 2028, the appropriate statutory implementation deadline.[139]

These Unit 4 Piñon Pine retirement considerations were rendered moot when in March 2024, the PUCN approved NV Energy's plans to continue operation of Tracy Unit 4 Piñon Pine to 2049.[140] In response, NDEP has revised the 2022 SIP Revision to incorporate a Four-Factor Analysis for Unit 4 Piñon Pine completed by NV Energy. The 2025 draft SIP Supplement relies on a mix of new and existing controls to reduce NOx emissions at Unit 4 Piñon Pine.[141] NDEP determined that existing steam injection measures to control NOx emissions are necessary for

[131] *Id.*; Conservation Organizations 2022 SIP Revision Comments at 23.
[132] *Id.* at 24-25.
[133] 2022 SIP Revision at 5-19 to 5-20.
[134] Conservation Organizations 2022 SIP Revision Comments at 30-32.
[135] 2025 SIP Supplement at 3-8.
[136] *Id.* at 3-5.
[137] *Id.* at i.
[138] 2022 SIP Revision at 5-19 to 5-20.
[139] Conservation Organizations 2022 SIP Revision Comments at 23-24.
[140] 2025 SIP Supplement at i.
[141] *Id.* at ii.

reasonable progress at Unit 4 Piñon Pine.[142] It further determined that SCR is necessary on top of existing controls to make reasonable progress towards a NOx emissions limit of 0.0151.[143]

2. The Revised SIP Fails to Correct Errors Identified in the 2022 SIP Revision.

a. NDEP Does Not Ensure that Utilization of Units 5 and 6 Remain Low.

Yet again, the 2025 SIP Supplement concludes that no additional controls are required at Units 5 and 6 because of recent historic low emissions and low.[144] As the Conservation Organizations explained in 2022, however, there are weak emissions controls at Units 5 and 6, and the units' low emissions are simply a result of their low utilization.[145] Furthermore, there is no guarantee that such a low utilization will not reverse course. Indeed, NV Energy's most recent IRP includes major load projections due to data center growth and this growth may lead to increased utilization at Units 5 and 6.[146] Additionally, emissions from Unit 4 Piñon Pine, presented in table 9 below, have grown 2020 to 2024 compared to 2016-2020.[147] A similar upward tick due to increased demand or strain on the grid could be replicated in Units 5 and 6, without any check from this SIP. The 2025 SIP's inaction in the face of this risk is not congruent with EPA's obligations under the regional haze rule. As our 2022 comments explain, when a state elects not to perform a Four-Factor Analysis, the state must incorporate the source's existing measures into the SIP to preserve the status quo.[148] Doing so prevents future visibility impairment, consistent with the Clean Air Act's visibility goal.[149] EPA's guidance makes clear that when a source's emissions are "below its permitted levels," a state must evaluate the "in place" measures and adopt related SIP measures that ensure reasonable progress.[150] A state may only forgo incorporating a source's existing emission limit measures into the SIP if the state shows that the measures are not necessary for reasonable progress based on a "robust technical demonstration."[151] The "existing" measure for Units 5 and 6 is low utilization. However, neither the 2022 SIP revision nor the 2025 SIP Supplement ensure that low utilization continues. Therefore, the SIP should be revised such that NDEP limits annual operating hours for Units 5 and 6 so that NOx emissions rates do not jump up at NV Energy's whim.

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[142] *Id.* at 3-3.
[143] *Id.* at 3-8, 3-10.
[144] *Id.* at 3-8.
[145] Conservation Organizations 2022 SIP Revision Comments at 25.
[146] NV Energy, Integrated Resource Plans, Volume 6 of 29: Narrative: Load Forecast, Market Fundamentals, Fuel and Purchase Power Price Forecasts at 83-84, https://www.nvenergy.com/about-nvenergy/rates-regulatory/recent-regulatory-filings.
[147] *See* 2025 Kordzi Report at 20.
[148] Conservation Organizations 2022 SIP Revision Comments at 24; *see also* Clarification Memo at 8-9; 2019 Guidance at 43.
[149] Clarification Memo at 8-9.
[150] 2019 Guidance at 43-44,
[151] Conservation Organizations 2022 SIP Revision Comments at 25; *see also* Clarification Memo at 9.

b. NDEP May Not Waive the BART Requirement that Unit 3 Operate SNCR.

In the SIP supplement, NDEP states that it 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."[152] As the Conservation Organizations highlighted in 2022 comments, EPA concluded that Unit 3's BART requirement was "low NOx burners with selective noncatalytic reduction," resulting in a 0.19 lbs/MMBtu emission limit.[153] Nevada state law also appears to require the installation of SNCR at Unit 3.[154] And yet, NV Energy has not installed SNCR at Tracy Unit 3 and NDEP is not requiring such compliance. NDEP should explain why SNCR is not required at Tracy Unit 3 despite federal and state law requirements and how such noncompliance is permitted within a legally-compliant SIP.

3. The Four-Factor Analysis for Tracy Unit 4 Piñon Pine in the Revised SIP Submission Has Significant Flaws.

a. The Unit 4 Piñon Pine Four-Factor Analysis Relies on Flawed Assumptions in the 2022 SIP Revision.

The revised SIP's Tracy Unit 4 Piñon Pine Four-Factor Analysis fails to correct a number of errors identified by the Conservation Organizations in 2022 comments and in Mr. Kordzi's 2022 report.[155] Each of these errors, fundamental to NV Energy's analysis that NDEP adopts without scrutiny, inflates NDEP's cost effectiveness estimate. These errors are explained in detail in Mr. Kordzi's 2022 report.

First, NDEP continues to incorrectly include a 4.6 percent sales tax in its cost effectiveness estimate. Nevada law explicitly exempts air pollution control equipment, such as SCR, from sales tax.[156]

Second, NDEP continues to improperly include an engineering, procurement, and construction ("EPC") contract surcharge in its estimate. The 10th Circuit determined that EPA's

[152] 2025 SIP Supplement at 3-5.
[153] Conservation Organizations 2022 SIP Revision Comments at 31; 2025 Kordzi Report at 23; *see also* EPA's proposal at 76 Fed. Reg. 36450, 36462 (June 22, 2011): "For unit 3, EPA proposes to agree with NDEP's analysis that BART for NOx is LNB with SNCR and an emission limit of 0.19 lb/ MMBtu, based on a 12-month rolling average."
[154] Nev. Admin. Code § 445B.22096: "low NOx burners with selective noncatalytic reduction" with an emission limit of 0.19 lbs/MMBtu based on a 12-month rolling average.
[155] *See* 2025 Kordzi Report at 20-21.
[156] Nev. Rev. Stat. § 361.077 ("All property . . . is exempt from taxation to the extent that the property is used as a facility, device or method for the control of air or water pollution."); *see also* Conservation Organizations 2022 SIP Revision Comments at 27.

Control Cost Manual's oversight methodology must be used in regional haze analyses.[157] That manual does not include or assume EPC cost surcharges at all, including for SCR installations.[158]

Third, NDEP continues to assume, without support, a 90 percent control efficiency for SCR.[159] As Mr Kordzi notes, a 90 percent control efficiency reflects an annual NOx emission rate of 0.0147 lb/MMBtu. However, SCR systems routinely achieve emissions rates more than 2 times lower, at 0.006 lb/MMBtu or even lower.[160] NV Energy and NDEP assume a far higher emission rate and therefore artificially and improperly low control efficiency, at 90 percent, but neither the 2025 nor 2022 SIP revision explains this choice. Indeed, the 2024 EPA Retrofit Cost Analyzer finds that SCR systems paired with NOx combustion controls can achieve NOx emission rates as low as 0.002 lb/MMBtu.[161] For Tracy Unit 4 Piñon Pine, that emission rate would result in an SCR control efficiency of more than 98 percent.[162] For his analysis correcting NDEP's cost-effectiveness calculations, Mr. Kordzi recommends a reasonable 94 percent SCR control efficiency, which reflects a controlled NOx emissions rate of 0.009 lbs/MMBtu – half the rate that NDEP assumes.[163]

Fourth, NDEP still assumes a 47 month construction time frame, without any rationale or support.[164] On the contrary, EPA assumes SCR systems can be installed within about 24 months, about half the time NDEP estimates. Using EPA's estimate would increase SCR's useful life by about two years, significantly impacting the cost-effectiveness analysis.[165]

Lastly, NDEP continues to assume total contingency costs that are unreasonably high. In particular, NDEP assumes a 5 percent process contingency of direct costs and a 15 percent project contingency of direct and indirect costs. The 2022 SIP Revision cites to EPA's Control Cost Manual to provide support for these estimates, but the Control Cost Manual contains no such support. Neither NV Energy nor NDEP offer additional rationale or explanation. Additionally, NV Energy based cost estimates on a 2019 vendor quote. Not only did NV Energy simply escalate that cost to 2024 dollars rather than retrieve an updated quote,[166] it also failed to follow EPA's Cost Control Manual's guidance in calculating contingency costs when using a vendor quote. The manual states that when a vendor quote is used, contingency costs should be

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157 *Oklahoma v. EPA*, 723 F.3d 1201, 1212 (10th Cir. 2013).

158 EPA Control Cost Manual, Section 1, Chapter 2 - Cost Estimation: Concepts and Methodology at 30 (Nov. 2017), https://www.epa.gov/sites/default/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf [hereinafter "EPA Control Cost Manual: Concepts and Methodology"]; *see generally* EPA Control Cost Manual: SCR].

159 2025 SIP Supplement, Appendix B at 12.

160 2022 Kordzi Report at 18-23.

161 EPA, Combustion Turbine NOx Technologies Memo at 4), prepared by Sargent & Lundy (Jan. 2022), https://www.epa.gov/power-sector-modeling/retrofit-cost-analyzer.

162 2022 Kordzi Report at 21.

163 2025 Kordzi Report at 23; *see also* 2022 Kordzi Report at 21.

164 *See* 2022 Kordzi Report at 21-22.

165 2022 Kordzi Report at 22.

166 2025 SIP Supplement at 3-6.

minimized. Consequently, Mr. Kordzi recommended that NDEP assume a more reasonable 10 percent total contingency.

b. The Unit 4 Piñon Pine Four-Factor Analysis Contains Additional Errors.

First, the Four-Factor Analysis uses an incorrect and inflated CEPCI.[167] The most recent annual CEPCI available is for 2023, yet NV Energy picks an arbitrary single month CEPCI from 2023 to represent 2024.

Second, as in the 2022 analysis, NDEP uses an incorrect NOx baseline for Unit 4 Piñon Pine. Average NOx emissions from 2020-2024 have gone up significantly compared to NOx emissions from 2016-2020.[168] Even though NDEP acknowledges that average emissions went up from 2016-2018 to 2016-2020, it determines that "[n]o changes were deemed necessary" to baseline emissions and uses out of date averages rather than updating baseline emissions.[169] Updating the baseline increases the 5-year average for Unit 4 Piñon Pine NOx emissions from 250 tons per year to 268 tons per year.[170]

Table 9: Updated Tracy Unit 4 Piñon Pine NOx Baseline

Unit	Year	Annual NOx Emission Rate (lbs/MMBtu)	NOx (tons)
Unit 4 Piñon Pine	2020	0.1527	293.2
Unit 4 Piñon Pine	2021	0.1525	267.9
Unit 4 Piñon Pine	2022	0.1681	231.4
Unit 4 Piñon Pine	2023	0.1523	249.4
Unit 4 Piñon Pine	2024	0.1493	300.2
5-year Averages		0.1550	268.4

c. Correcting the Unit 4 Piñon Pine Four-Factor Analysis Yields an SCR Cost-Effectiveness Estimate Less Than Half of NDEP's Estimate.

The table below reflects Mr. Kordzi's reasonable corrections to NDEP/NV Energy's Four-Factor Analysis. The corrected cost-effectiveness analysis yields a significantly lower

[167] 2025 Kordzi Report at 14, 21.
[168] *Id.* at 23.
[169] 2025 SIP Supplement at 3-4.
[170] 2025 SIP Supplement at 3-4.

number, one well under EPA's $10,000 cost-effectiveness threshold, at $4,454 per ton of NOx.[171]

Table 10: Updated Tracy Unit 4 Piñon Pine SCR Cost-Effectiveness

Cost Item	NVE	Revised	Comments
Total Equipment Cost (A)	$3,075,900	$3,075,900	
Sales Tax (0.046 * A)	$141,491	**-$141,491**	**Delete sales tax on pollution control equipment as discussed in 2022 Kordzi Report**
Freight	$58,250	$58,250	
Total Purchased Equipment Cost ("PEC")	$3,275,641	$2,992,659	
Direct Installation Costs	$2,292,500	$2,292,500	
Total Direct Costs (TDC - Equip. + Installation)	$5,568,141	$5,285,159	
Indirect Costs			
General Facilities (5% of TDC)	$278,407	$264,258	
Engineering/Home Office (10% of TDC)	$556,814	$528,516	
Process Contingency (5% of TDC)	$278,407	**$0**	**Process contingency deleted as discussed in 2022 Kordzi Report**
Total Indirect Costs (B)	$1,113,628	$792,774	
Contingency Percentage (%)	15	**10**	**Reduce total contingency to 10% as discussed in 2022 Kordzi Report**
Contingency (Percent of (A+B))	$1,002,265	$607,793	
Total Capital Investment (TCI = A+B+ Contingency)	$7,684,035	$6,685,726	
Surcharge for EPC Contract (15% of TCI)	$1,152,605	**$0**	
Total Capital Investment 2019	$8,836,640	$6,685,726	
CEPCI 2019	607.5	607.5	
NV Energy CEPCI for 2024	824.5		**NV Energy incorrect CEPCI for 2024**
CEPCI for 2023		**797.9**	**Correct CEPCI for 2023**

[171] 2025 Kordzi Report at 23.

Total Capital Investment 2024	$11,993,102	$8,781,137	
Equipment Life (years)	30	30	
Interest Rate (%)	6.75	**6.95**	**NV Energy's correct Interest Rate**
Capital Recovery Factor ("CRF")	0.0786	0.0802	
Annualized Capital Costs (CRF * TCI)	$942,324	$704,089	
Annual Operating Cost	$419,611	$419,611	**As adjusted by NVE in its third response letter**
Total Annual Cost	$1,361,935	$1,123,700	
Control Efficiency (%)	90	**94**	**Increase SCR control efficiency as discussed in 2022 Kordzi Report**
Baseline NOx Emissions (tons)	250.0	**268.4**	**Update NOx baseline**
Emissions Reduction (tons)	225.0	252.3	
Cost-Effectiveness ($/ton)	$6,053	**$4,454**	

III. The Permit Provisions NDEP Proposes to Incorporate Into the SIP Are Not Practically Enforceable.

A number of the emission limits and other regulatory provisions that NDEP proposes to incorporate into the SIP are not practically enforceable. A number of the provisions are too vague to adequately identify the requirements with which facilities must comply or they do not contain adequate monitoring, recordkeeping, and reporting requirements. NDEP must correct the problems with the provisions proposed for inclusion in the SIP discussed below before submitting this Supplement to EPA.

The Clean Air Act requires that all SIPs, including Regional Haze SIPs, contain elements sufficient to ensure emission limits are practically enforceable. A state's long-term strategy must contain "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal."[172] This includes sufficient monitoring, recording, and recordkeeping requirements to allow states, EPA, and the public to determine whether sources are complying with applicable SIP requirements.[173] Emission

[172] 42 U.S.C. § 7491(b)(2); 40 C.F.R. § 51.308(f)(2)(i); *see also* 42 U.S.C. § 7410(a)(2)(A) (requiring that SIPs must include "enforceable emission limitations and other control measures, means, or techniques. . ., as well as schedules and timetables for compliance, as may be necessary").

[173] 42 U.S.C. § 7410(a)(2)(F) (requiring SIPs to provide for "the installation, maintenance, and replacement of equipment, and the implementation of other necessary steps . . . to monitor emissions from []sources," as well as "periodic reports on the nature and amounts of emissions

limitations and the measures necessary for the SIP must be adopted as rules and regulations, and those rules and regulations must be included in the SIP and made publicly available during the notice and comment period on proposed SIPs.[174] In order for EPA to determine that a SIP submission is "complete" under the Act, the SIP must provide "[e]vidence that the plan contains emission limitations, work practice standards and recordkeeping/reporting requirements, where necessary, to ensure emission levels," as well as "[c]ompliance/enforcement strategies, including how compliance will be determined in practice."[175]

Here, however, Draft of Proposed Regulation R138-24, which contains new emission limits and control requirements for Tracy and Valmy that NDEP identified as necessary to make reasonable progress in the Supplement are vague. For instance, the regulations indicate that Tracy and Valmy shall "[i]nstall, calibrate, maintain and operate a continuous monitoring system and record the output of the system for NOx emissions in compliance *with the requirements of this chapter*."[176] Similarly, the regulations indicate that Tracy and Valmy must submit an annual report "in accordance with the *reporting requirements of this chapter* and 40 C.F.R. Part 75."[177] Nothing in the SIP Supplement or the proposed regulation clearly identifies the other requirements "in this chapter" with which the facilities must comply. Nor does the Supplement or proposed regulation indicate whether those requirements conflict with the annual reporting requirements in 40 C.F.R. Part 75. Without specifying exactly which requirements the facilities must adhere to, it is impossible for the public or EPA to identify exactly which requirements NDEP is proposing to incorporate into the SIP to ensure compliance with the emission limits identified as necessary to make reasonable progress.

Additionally, the permit provisions encompassing the existing measures for Tracy that NDEP proposes to incorporate into the SIP do not provide sufficient monitoring, recordkeeping, and reporting requirements. The Tracy permit requires that the facility "shall maintain a file of all measurements" using a continuous emissions monitoring system ("CEMS"), but does not require that the facility actually submit the CEMS measurement to the State.[178] Rather, the only records the permit requires Tracy to submit are for excess emissions.[179] To satisfy the requirements of the Clean Air Act and the RHR, this provision as incorporated into the SIP must require that *all* compliance records be submitted to the State, and not just maintained on site, to ensure that both the State, the public, and EPA have an adequate opportunity to review records

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and emissions-related data"); 40 C.F.R. § 51.308(f)(6)(vi) (requiring haze SIPs to include "reporting, recordkeeping, and other measures, necessary to assess and report on visibility").
[174] 40 C.F.R. § 51.281.
[175] *See also id.* § 51.103(a) (providing that "[t]he State makes an official plan submission to EPA only when the submission conforms to the requirements of appendix V to this part…").
[176] 205 SIP Supplement, Appendix C (PDF p. 203), Proposed Regulation of the State Environmental Commission LCB File No. R138-24, Section 1.3(a) (Sept. 17, 2024) (emphasis added) [hereinafter "Proposed Regulation"].
[177] Proposed Regulation (PDF p. 203) (emphasis added).
[178] 2025 SIP Supplement, Appendix A.2 (PDF p. 101), Nev. Dep't Conservation & Nat. Res., Permit No. AP4911-0194.04, Class I Air Quality Operating Permit: Tracy Power Generating Station at 131, Section V.C.3 (issued Mar. 23, 2022) [hereinafter "Tracy Permit"].
[179] Tracy Permit at 131 (PDF p. 101), Section V.C.2.

and ensure the facility is complying with its applicable emission limits.[180] Additionally, the permit requires that emission measurement records be maintained for only 2 years.[181] NDEP must ensure that the provision incorporated into the SIP requires that records be maintained for at least five years to allow the public to properly enforce the emission limits, as the statute of limitations for an enforcement action is five years.[182] As EPA explained in a recent SIP action, "reporting requirements serve multiple purposes, including promoting transparency, providing deterrence against violations, and supporting effective enforcement of SIP requirements" and the failure of a SIP to include adequate reporting requirements "can undermine citizens' ability to participate in the enforcement of the SIP as authorized" under the Clean Air Act.[183]

The permit provisions for the Graymont Pilot Peak similarly do not contain adequate monitoring, recordkeeping, and reporting requirements. Just as with the Tracy permit, the Graymont permit only requires the facility to submit to the State its excess emission reports, and does not require the facility to submit its emission measure reports.[184] This provision as incorporated into the SIP must require that *all* compliance records be submitted to the State to ensure that the State and the public can access the records to verify compliance.[185] The Graymont permit also only requires the facility to maintain records onsite for two years.[186] NDEP must require the facility to maintain records for at least five years to allow the public to enforce the permit limits if necessary.[187]

Finally, both the Graymont and the Lhoist Apex permits incorporate by reference the requirements of 40 C.F.R. Part 60, which requires both facilities to develop and set a Quality Control Program.[188] However, nothing in the SIP Supplement or the permits included in the Supplement actually set forth the requirements of the facility Quality Control Programs. To satisfy the requirement that the SIP contain *all* measures necessary to ensure compliance, the emission limits necessary to make reasonable progress, NDEP must propose to include in the SIP

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[180] *See e.g.* 42 U.S.C. § 7410(a)(2); 40 C.F.R. § 51.116(c); *id.* § 51.211; *id.* § 51.230(f); *see also* 42 U.S.C. § 7604(a), (f).
[181] Tracy Permit at 131 (PDF p. 101), Section V.C.3.e.(1).
[182] *See, e.g.*, *Sierra Club v. Okla. Gas & Elec. Co.*, 816 F.3d 666, 670 (10th Cir. 2016) ("Because the CAA does not specify a statute of limitations for bringing a citizen suit for civil penalties, the default five-year statute of limitations for civil penalties, fines, and forfeitures under federal law applies.").
[183] 89 Fed. Reg. 63852, 63854 (Aug. 6, 2024) [hereinafter "EPA CO Ozone Proposal"].
[184] 2025 SIP Supplement, Appendix A.3 (PDF p. 127-28), Nev. Dep't Conservation & Nat. Res., Permit No. AP3274-1329.03, Class I Air Quality Operating Permit: Graymont Western US Inc. – Pilot Peak Plant at 143-44, Section V.C.2. to V.C.3. (issued June 14, 2024) [hereinafter "Graymont Permit"].
[185] *See e.g.* 42 U.S.C. § 7410(a)(2); 40 C.F.R. § 51.116(c); *id.* § 51.211; *id.* § 51.230(f); *see also* 42 U.S.C. § 7604(a), (f).
[186] Graymont Permit at 144 (PDF p. 128), Section V.C.3.e.(1).
[187] *Sierra Club*, 816 F.3d at 670; EPA CO Ozone Proposal, 89 Fed. Reg. at 63854.
[188] Graymont Permit at 142 (PDF p. 126), Section V.B.3; 2025 SIP Supplement, Appendix A.1 (PDF p. 60), Clark Cnty. Dep't Env't & Sustainability, Authority to Construct Permit: Lhoist North America of Arizona Apex Plant at 8, Section 4.1(3) (reissued Feb. 6, 2024).

the facility Quality Control Programs themselves.[189] NDEP must include those Programs in the SIP via a separate Supplement to allow the public the opportunity to review and comment on the Programs.[190]

IV. NDEP's Glidepath Adjustment for Jarbidge Does Not Satisfy the Purpose and Requirements of the Regional Haze Program.

In the SIP Supplement, NDEP adjusts the projected 2028 Reasonable Progress Goal ("RPG") for the Jarbidge Wilderness Area to account for the additional controls required in the Supplement for Valmy and Tracy.[191] As NDEP explains, although the round RPG is still 7.76, as it was in the 2022 SIP Revision, the controls required in the Supplement result in 0.001 deciview decrease in the projected 2028 RPG and is below the "adjusted" Uniform Rate of Progress ("URP") glidepath for the Class I area.[192] Yet, with the additional improvement in visibility impairment at Jarbidge resulting from the controls NDEP requires in the SIP Supplement, the projected 2028 RPG for Jarbidge is still above the unadjusted URP for this Class I area.[193]

The Regional Haze Rule requires states to calculate baseline, current, and natural visibility conditions, as well as the URP for each Class I area within their borders, which is the amount of progress that would ensure that natural visibility conditions are achieved if kept constant each year.[194] This calculation shows a straight-line "glidepath" between baseline visibility conditions and natural visibility conditions. States must also develop RPGs, expressed in deciviews, for all in-state Class I areas reflecting the visibility conditions that will be achieved at the end of the implementation period as a result of the measures included a state's long-term strategy. [195] States must then compare those goals to the URP to track the amount of progress that will be made at each Class I area.[196] The Regional Haze Rule allows states to adjust the URP glidepaths to account for international and prescribed wildland fire emissions.[197] However, these adjustments must be made "using scientifically valid data and methods" and must be approved by the EPA Administrator.[198]

In the 2022 SIP Revision, NDEP explained that it adjusted the URP glidepath endpoints for Jarbidge, and other out-of-state Class I areas, based on prescribed wildland fire and

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[189] 42 U.S.C. § 7491(b)(2); 40 C.F.R. § 51.103(a); *id.* § 51.308(f)(2)(i); *see also* 42 U.S.C. § 7410(a)(2).
[190] 40 C.F.R. § 51.281.
[191] 2025 SIP Supplement at 2-9, 3-13, 5-4.
[192] *Id.* at iii-iv, 5-4.
[193] 2022 SIP Revision at 6-8 (Fig. 6-2) (showing the unadjusted URP for Jarbidge, compared to the adjusted URP).
[194] 40 C.F.R. § 51.308(f)(1).
[195] *Id.* § 51.308(f)(3)(i).
[196] *Id.* § 51.308(f)(3).
[197] *Id.* § 51.308(f)(1)(vi)(B).
[198] *Id.*; 82 Fed. Reg. at 3104 (explaining that adjustment for international emissions "would be available only when and if these impacts can be estimated with sufficient accuracy").

international emissions.[199] These adjustments allow the State to "flatten out" the glidepath for Jarbidge to make it *appear* that the Class I area is on track to meet the Clean Air Act's goal of achieving natural visibility conditions when that is not the case. As a result, the adjusted URP for Jarbidge does not reflect "the rate of progress that would reach true natural visibility conditions" at that Class I area.[200]

Here, NDEP relied on modeling from the Western Regional Air Partnership ("WRAP") following EPA's 2019 Modeling Guidance and Technical Support Document ("EPA 2019 Modeling TSD").[201] However, EPA's 2019 Modeling TSD does not provide scientifically sound data or methods for making the glidepath adjustments—a point EPA itself has acknowledged. In its 2019 Modeling TSD, EPA highlighted substantial problems with available data and methods for adjusting Class I glidepaths based on both international and prescribed wildland fire emissions.[202] The WRAP also recognized the uncertainties inherent in glidepath adjustments based on both international and prescribed wildland fire emissions, stating that "it is difficult to tell a priori which approach for adjusting the URP Glidepath to account for contributions of international (IE) and [prescribed] fire will work best in all cases."[203]

As explained in the Conservation Organizations' comments on the 2022 SIP Revision, NDEP should not use international or prescribed wildland fire emissions to justify flattening out the URP glidepath for Jarbidge and justify avoiding reasonable and cost-effective controls on

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[199] 2022 SIP Revision at 6-8 ("NDEP has chosen to adjust the 2064 natural conditions and glideslope for Jarbidge Wilderness Area to account for international and prescribed fire emissions, provided by the WRAP.").
[200] *See* 82 Fed. Reg. at 3105.
[201] 2022 SIP Revision at 6-8; *see also* W. Reg'l Air P'ship, Procedures for Making Visibility Projections and Adjusting Glidepaths Using the WRAP-WAQS 2014 Modeling Platform at 26 (2021) [hereinafter "WRAP Glidepath Adjustments"] (attached as Ex. 18); *see generally* EPA, Technical Support Document for EPA's Updated 2028 Regional Haze Modeling (Sept. 2019) [hereinafter "EPA 2019 Modeling TSD"] (attached as Ex. 19).
[202] EPA 2019 Modeling TSD at 37, 67 (explaining that URP adjustment for international emissions was based on just one year of data, that adjust method was questionable, and that "[d]ue to the uncertainty in many of the calculations and modeling and ambient data, additional scrutiny of the initial glidepath adjustments are warranted"); *id.* at 35, 54-55, 67 (declining to include prescribed fire contributions in its adjusted URPs and identifying significant data and modeling limitations for prescribed fire emissions, including that (1) there is limited existing emissions data for prescribed fires, and that data does not accurately capture the significant variability in these emissions from year-to-year; (2) the categorization of fires between wildfires (which are considered natural emissions) and prescribed fires (which are considered anthropogenic emissions) is uncertain, particularly in the West; and (3) prescribed fire impacts are likely already reflected in natural wildfire impacts when estimating ambient natural conditions on the 20% most impaired days, likely resulting in double-counting of these emissions).
[203] WRAP Glidepath Adjustments at 26, 28 (stating that "it is difficult to tell a priori which approach for adjusting the URP Glidepath to account for contributions of international (IE) and [prescribed] fire will work best in all cases.").

sources that contribute to impairment at this Class I area.[204] Rather than pointing a finger at and using international and prescribed fire emissions to adjust the glidepath, NDEP must determine what emission reductions measures are available and necessary for sources in the state to make reasonable progress in the second implementation period.[205]

Moreover, because the projected 2028 RPG for Jarbidge is above the unadjusted URP for that Class I area, NDEP must provide a technically "robust demonstration" that no other control measures should be included in the SIP.[206] That demonstration must be based on a careful consideration of the four statutory factors and show that "there are no additional emission reduction measures for anthropogenic sources or groups of sources" that can reasonably be anticipated to contribute to visibility improvement in the affected Class I area.[207] "The purpose of this demonstration is to show that a state conducted its analysis in a reasonable manner and that there are no additional measures that would be reasonable to implement in a particular planning period."[208] As discussed in detail above, there are readily available, feasible, and cost-effective control measures that would further reduce haze-forming emissions affecting the Jarbidge Wilderness Area from the Valmy and Tracy plants.[209] Thus, NDEP must require these additional controls identified above to satisfy its robust demonstration requirement under the Regional Haze Rule.

V. Conclusion

The Clean Air Act's Regional Haze Program presents an excellent opportunity for NDEP to not only improve visibility at Jarbidge Wilderness Area and other nearby Class I areas, but also to improve air quality in communities across the state. Although the Clean Air Act and RHR direct that the State to make reasonable progress toward the natural visibility goal in the second planning period, NDEP relied on highly flawed facility-submitted control analyses, causing the agency to inappropriately reject cost-effective emission reductions for sources that contribute to visibility impairment in Class I areas across the region. NDEP must revise the SIP Supplement to address the legal requirements of the Clean Air Act and RHR discussed above and in the attached expert report.

We appreciate NDEP's consideration of these comments. Please do not hesitate to contact us with any questions.

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[204] Conservation Organizations 2022 SIP Revision Comments at 45.
[205] 82 Fed. Reg. at 3093 (explaining that "the rate of progress that will be achieved by the emission reductions resulting from all reasonable control measures is, by definition, a reasonable rate of progress.").
[206] 40 C.F.R. § 51.308(f)(3)(ii)(A); *see also id.* § 51.308(d)(1)(ii) (similar).
[207] *Id.* § 51.308(f)(3)(ii)(A); 82 Fed. Reg. at 3099.
[208] 82 Fed. Reg. at 3099.
[209] *See supra* Sections II.C-D.

Sincerely,

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EXHIBIT LIST

1	NPCA et al., Conservation Organizations 2022 SIP Revision Comments (July 25, 2022)
2	Joe Kordzi, A Limited Review of the Nevada Regional Haze State Implementation Plan (“2022 Kordzi Report”) (July 2022)
3	Joe Kordzi, A Partial Review of the Nevada Regional Haze State Implementation Plan Revision (“2025 Kordzi Report”) (Mar. 2025)
3a	North Valmy 1 SCR CCM cost-effectiveness-2025.xlsm
3b	North Valmy 1 SNCR CCM cost-effectiveness-2025.xlsm
3c	North Valmy 2 SCR CCM cost-effectiveness-2025.xlsm
3d	North Valmy 2 SNCR CCM cost-effectiveness-2025.xlsm
3e	NV Tracy Valmy Emissions.xlsx
3f	Tracy Unit 3 SCR CCM cost-effectiveness-2025.xlsm
3g	Tracy Unit 4 Pinion Pine SCR-2025.xlsx
4	NPCA, Polluted Parks: How Air Pollution and Climate Change Continue to Harm America’s National Parks (2024)
5	U.S. Forest Serv., National Visitor Use Monitoring Survey Results: National Summary Report (Sept. 2023)
6	NPS, 2023 National Park Visitor Spending Effects (Aug. 2024)
7	Bureau Econ. Analysis, Outdoor Recreation Satellite Account (ORSA): 2023—Nevada (2025)
8	David Keiser et al., Air pollution and visitation at U.S. national parks, 4 Sci. Advances 3-6 (July 18, 2018)
9	EPA, Health Effects of Ozone Pollution (last updated Mar. 13, 2025),
10	EPA, Basic Information About NO2 (last updated July 16, 2024)
11	EPA, Health and Environmental Effects of Particulate Matter (PM) (last updated July 16, 2024)
12	EPA, Sulfur Dioxide Basics (last updated Jan. 10, 2025)

13	EPA, Ecosystem Effects of Ozone Pollution (last updated Oct. 21, 2024)
14	Memorandum from Peter Tsirigotis, Dir., EPA, to Reg'l Air Dirs., Regions 1-10 (Aug. 20, 2019)
15	In the Matter of Proposed Revisions to Regulation Number 23, Colo. Dep't Pub. Health & Env't, Air Pollution Control Div., Prehearing Statement (Oct. 7, 2021)
16	N.M. Env't Dep't, Air Quality Bureau, Excerpt of State of New Mexico Revised Proposed Regional Haze State Implementation Plan Revision Second Planning Period (2019 – 2028) (revised Feb. 7, 2025)
17	Memorandum from Peter Tsirigotis, Dir., EPA, to Reg'l Air Dirs., Regions 1-10 (July 8, 2021)
18	W. Reg'l Air P'ship, Procedures for Making Visibility Projections and Adjusting Glidepaths Using the WRAP-WAQS 2014 Modeling Platform (2021)
19	EPA, Technical Support Document for EPA's Updated 2028 Regional Haze Modeling (Sept. 2019)

Appendix G.5 – NDEP Responsiveness Summary

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Nevada Division of Environmental Protection Bureau of Air Quality Planning

Responsiveness Summary to Public Comments

Pursuant to 40 CFR 51.102, NDEP made its draft Nevada Regional Haze SIP Revision available for public review beginning February 28, 2025. A hearing was scheduled for April 4, 2025, on condition that NDEP would hold a hearing if a written request was received. NDEP welcomed written public comments and requests to hold a hearing until March 31, 2025. The hearing scheduled for April 4, 2025, was later cancelled, as NDEP did not receive a request to hold the hearing. Evidence of public participation is provided below.

NDEP received comments from the following organizations:

- NV Energy on March 21, 2025.
- National Parks Conservation Association, Sierra Club, and Coalition to Protect America's National Parks (collectively, "Conservation Organizations") on March 31, 2025.

NDEP responses to comments received during the public notice period are provided below.

NV Energy Comments on permit requirements incorporated by reference

Comment 1: In the Tracy Generating Station Permit, Section M.1.b. "CO and VOC emission from S2.066 and S2.067 shall be controlled by an Oxidation catalyst for control" should be in strikeout (not included) in the Regional Haze SIP Revision.

Response 1: NDEP Thanks NV Energy for its comment and agrees that Section M.1.b of Tracy Generating Station's Permit should not be incorporated by reference into Nevada's Regional Haze SIP Revision. The inclusion of this permit requirement was an oversight as it is a requirement for CO and VOC emissions, and the condition is now in strike out (not included).

Comment 2: In the Tracy Generating Station Permit, Section V. Continuous Emissions Monitoring system (CEMS) Conditions (continued), A.8.c.(1)(c) "Annual 2-load flow RATA or annual 3-load flow RATA" should be in strikeout. The requirement to conduct a flow relative accuracy test audit (RATA) is not applicable to the facility as Tracy Station units all qualify as "gas-fired" as defined in 40CFR72.2.

Response 2: NDEP agrees with NV Energy's comment that the requirement to conduct a flow relative accuracy test audit (RATA) is not applicable to the facility as Tracy Station units all qualify as "gas-fired" as defined in 40CFR72.2. 40 CFR 75.10(a)(5), states that "A single certified flow monitoring system may be used to meet the requirements of paragraphs (a)(1) and (a)(3) of this section. A single certified diluent monitor may be used to meet the requirements of paragraphs (a)(2) and (a)(3) of this section. A single automated data acquisition and handling system may be used to meet the requirements of paragraphs (a)(1) through (a)(4) of this section". NDEP will strike out section in the Revised RH SIP, since paragraph (a)(2) specifically references NO_x and what is required.

Conservation Organizations Comments

Cost Effectiveness
Comment 1: NDEP's cost threshold is reasonable and appropriately meets requirements for assessing the Clean Air Act's four statutory factors.

Response 1: NDEP thanks the Conservation Organizations for their review of the Nevada 2024 draft Regional Haze State Implementation Plan Revision for the Second Planning Period and appreciates their comments.

Q/D Analysis
Comment 2: NDEP still does not identify other Class I areas impacted by the plant, and does not provide Q/d values for any of those other areas. NDEP must provide more information about how each source contributes to visibility impairment in Class I areas, including those in neighboring states, not just the Class I area nearest to the source.

Response 2: NDEP acknowledges and appreciates this comment. In Appendix D.6 of the 2022 Regional Haze SIP submitted to the EPA, NDEP addresses this comment and states that for sources that were identified by NDEP's Q/D analysis, excluding airports and sources that have permanently shut down, Q/D values for the 3 nearest class I areas are now provided in Table 5-1 of the 2022 Regional Haze SIP.

North Valmy Generating Station
Comment 3: North Valmy NO_X Baseline Is Unsupported.

Response 3: NDEP acknowledges this comment and requested additional information from NV Energy to support the NO_X baseline. NV Energy replied that when firing natural gas, Units 1 & 2 at the North Valmy Station will have different boiler efficiencies than they did during the baseline period when firing coal (Response to Comment 3, Appendix F.3). NV Energy calculated projected actual NO_X emissions for Valmy Units 1 and 2 when converted to natural gas using Low NO_X burners (LNBs) and the following information:

- Heat Input: Unit 1, 2,554 MMBtu/hr; Unit 2, 3,058 MMBtu/hr.
- AP-42 Low NO_X burner emission rate: 0.1373 lb/MMBtu (140 lb/10^6 scf ÷ 1020 Btu/scf)
- Capacity Factors: Unit 1, 22.4% (Updated Four Factor Analysis for the NV Energy North Valmy and Tracy Generating Stations, dated March 18, 2024, Appendix A, PDF pages 33 and 41) and Unit 2, 24.9% (Updated Four Factor Analysis for the NV Energy North Valmy and Tracy Generating Stations, dated March 18, 2024, Appendix A, PDF pages 48 and 56)
- Unit 1 calculation= 2,554 MMBtu/hr * 0.137 lb/MMBtu * 8760 hours/year* 0.224 capacity factor ÷ 2000 lb/ton= 344.6 tons.
- Unit 2 calculation= 3,058 MMBtu/hr * 0.137 lb/MMBtu * 8760 hours/year* 0.249 capacity factor ÷ 2,000 lb/ton= 457.8 tons.

The projected actual emissions result in approximately 5% increase in NO_X emission over baseline emissions.

Comment 4: NDEP's North Valmy Electricity Generation Projections Are Unreasonably Low and Not Representative.

Response 4: NDEP acknowledges this comment and agrees that there is variability in utilization data at North Valmy Generating Station due to the COVID-19 pandemic, natural gas distribution issues and the scheduled departure of the Idaho Power Company. NDEP requested additional information on future electric output projections from NV Energy. NV Energy responded with 3 different future electric output projections for North Valmy Generating Station (NV Energy Response Letter 9, Appendix F.1) of which the model with the highest utilization did not vary greatly from the 2016-2018 baseline. NDEP has also reviewed NV Energy's 5th Amendment to its Integrated Resource Plan and verified that the Idaho Power Company is not planning to depart usage of North Valmy Generating Station. After reviewing the NPS detailed feedback (Appendix E), NV Energy's responses (Appendix F) and comments from the Conservation Organizations, NDEP decided to retain the original baseline to maintain consistency with the baseline established in the SIP for the Regional Haze Round Second Planning Period.

Comment 5: NDEP's SCR and SNCR Efficiency Assumptions for North Valmy Are Unreasonably Low.

Response 5: NDEP requested additional information from NV Energy regarding the SCR and SNCR efficiency assumptions for the North Valmy Generating Station (NV Energy Response Letter 11, Appendix F.3). NV Energy provided documentation showing that the emissions rate of 0.137 lb NO_X/MMBTU, with low NO_X natural gas fired burners, was calculated using Table 1.4-1 of the US EPA's AP-42 (Response to Comment 5, Appendix F.3). NV Energy cited the conversion of the Cholla Generating Station in Arizona as a recent example of SNCR reducing NO_X emissions by 25% and Chapter 2, Section 4.2 of the EPA's Control Cost Manual as the basis for a 78% reduction using SCR. Moreover, 0.03 lb/MMBtu was identified by the EPA in 2023 as the basis for establishing future NO_X allowances for natural gas-fired boilers equipped with SCR when promulgating the Good Neighbor Plan requirements (40 CFR 97.1010(a)(4)(iii)(B)(2)).

Comment 6: NDEP's Estimated Annual MWh Output Is Too Low.

Response 6: NDEP acknowledges this comment and recognizes that there is variability in MWh output at North Valmy Generating Station due to the COVID-19 pandemic, natural gas distribution issues and the scheduled departure of IPC as mentioned in response 4. After reviewing the NPS detailed feedback (Appendix E), NV Energy's filing of its Integrated Resource Plan with the Public Utilities Commission of Nevada, NV Energy's responses (Appendix F) and comments from the Conservation Organizations, NDEP decided to retain the original baseline to maintain consistency with the baseline established in the SIP for the Regional Haze Round Second Planning Period.

Comment 7: NDEP's Net Plant Heat Rate Is Too High.

Response 7: NDEP acknowledges this comment and requested additional information from NV Energy to support the Net Plant Heat Rate. In Response to Comment 7 of Appendix F.3, NV Energy states that it commissioned an engineering study in 2019 to assess the feasibility of converting Units 1 and 2 at North Valmy from coal to natural gas firing. This study concluded that the boiler efficiency of each unit would decrease by 5.8% following conversion to natural gas firing. This efficiency loss is due to the increase in the water content of the flue gas for natural gas firing compared to coal firing. The expected decrease in boiler efficiency means that the net heat rates for Units 1 and 2 when firing natural gas would be expected to increase in proportion to the efficiency decrease compared to the actual net heat rates that each unit exhibited during the baseline period when firing coal.

Based on data provided to the EPA Clean Air Markets Program, the actual net heat rates for Units 1 and 2 during 2016-2018 baseline period were 10.175 MMBtu/net MW and 10.949 MM Btu/net MW, respectively. Accordingly, the projected net plant heat rates used for the SCR and SNCR cost comparisons were calculated as follows:

Unit 1: 10.175 MMBtu/MW x 1.058 = 10.765 MMBtu/MW

Unit 2: 10.949 MMBtu/MW x 1.058 = 11.584 MMBtu/MW

Comment 8: NDEP's Inlet and Outlet SNCR NO_X Rates Are Unreasonable and Unsupported.

Response 8: NDEP acknowledges and thanks the Conservation Organizations for their comment. NDEP requested additional information from NV Energy documenting the Inlet and Outlet SNCR NO_X Rates for the North Valmy Generating Station (Request 4, Appendix F.1). 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 noncatalytic 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.

Comment 9: NDEP's Normalized Stoichiometric Ratio Is Unsupported.

Response 9: NDEP acknowledges this comment and requested additional information from NV Energy to support the Net Plant Heat Rate, which was provided in NV Energy's Response Letter 11, Appendix F.3. NV Energy responded that it recognized that increasing the ratio would worsen the cost-effectiveness and used the minimum "Typical" NSR value recommended by EPA in the Cost Control Manual so as not to adversely bias the calculated cost effectiveness of this alternative.

Comment 10: NDEP Uses Incorrect Values for the Concentration and Cost of Reagent.

Response 10: NDEP acknowledges this comment and respectfully disagrees. NDEP requested further information on the anhydrous ammonia reagent used by NV Energy. NV Energy responded that it uses a 19% aqueous ammonia solution for process safety reasons with a current cost of $1.70 per gallon which is 79% higher than the $0.95 cost used in the four-factor analysis (NV Energy Response Letter 10, Appendix F.2). While this cost is higher than the cost of 29% ammonia concentrations used in Mr. Kordzi's report, the EPA Cost Control Manual Page 1-11 states "however, the choice of reagent is based not only on cost but also on physical properties and operational considerations". NDEP will consider the actual costs as provided by NV Energy, including the percentage of aqueous ammonia that NV Energy operationally chooses as a safety requirement.

Comment 11: NDEP's Chemical Engineering Plant Cost Index Value Is Too High.

Response 11: NDEP agrees that the CEPCI value used by NV Energy in its four-factor analysis was not the finalized 2023 value but instead an unfinalized 2023 value which was available at the time the analysis was performed. NV Energy provided an updated cost estimate using the finalized 2023 CEPCI value (NV Energy Response Letter 10, Appendix F.2). NDEP verified that the cost estimate for SCR is still above the $10,000/ton threshold and has updated the cost estimates in Section 2.3.

Comment 12: NDEP's Cost of Electricity Value Is Unsupported.

Response 12: NDEP acknowledges this comment and requested additional information from NV Energy to support the Cost of Electricity Value. NV Energy replied that the $0.075/kWh figure was used for the cost of electricity to provide consistency with the 2020 four-factor analysis (Response to Comment 12, Appendix F.3). This value was previously discussed in NV Energy Response Letter 3, Appendix B.5.e of Nevada's 2022 Regional Haze SIP and includes both the cost of electricity and cost of capacity replacement.

Comment 13: NDEP's Fuel Cost Is Unsupported.

Response 13: NDEP acknowledges this comment and requested additional information from NV Energy to support the Fuel Cost of $1.66/MMBtu. NV Energy acknowledged that using the current U.S. Energy Information Administration value of $3.36/MMBtu would have the effect of worsening the cost-estimate (Response to Comment 13, Appendix F.3). NV Energy used the same cost figure in the 2020 four-factor analysis which is more conservative.

Comment 14: NDEP Underestimates the Cost-Effectiveness of SNCR at North Valmy.

Response 14: NDEP thanks the Conservation Organizations for their independent review of the cost effectiveness of SNCR installation at North Valmy Generating Station. NDEP acknowledges the differences between Mr. Kordzi's report and those found in NV energy's four-factor analysis, including changes to the CEPCI, results in a lower SNCR cost effectiveness estimate. NDEP requested NV Energy update its four-factor analysis to include the 2023 CEPCI value and requested clarification on its reagent cost (Appendix F). After reviewing NV Energy's responses to NDEP's request for additional information NDEP maintains that SNCR's cost effectiveness meets the $10,000/ton threshold.

Comment 15: NDEP's Inlet and Outlet SCR NO_X Rates Are Unsupported.

Response 15: NDEP requested additional information from NV Energy regarding the Inlet and Outlet SCR NO_X Rates for the North Valmy Generating Station (NV Energy Response Letter 11, Appendix F.3). NV Energy replied that as explained above in the response to Comment 5, the basis of the NO_X emission rate at the SCR inlet is the NO_X emission factor for large natural gas-fired boilers employing Low NO_X burners from EPA's AP-42 Table 1.4-1. Also as explained above, the basis of the NO_X emission rate at the SCR outlet is the emission rate that EPA used to establish future NO_X allowances for natural gas-fired boilers equipped with SCR under the Good Neighbor Plan.

Comment 16: NDEP's Catalyst Life Value for SCR Is Unreasonably Low.

Response 16: NDEP requested additional information from NV Energy regarding the Catalyst Life Value for SCR. NV Energy replied that 24,000 hours is the default estimated catalyst operating life that is pre-populated in the EPA's Control Cost Estimation Spreadsheet for Selective Catalytic Reduction. NV Energy has consistently used this value for the SCR cost estimates for the North Valmy Station for both the original and updated Four Factor Analysis (NV Energy Response Letter 11, Appendix F.3).

Comment 17: NDEP underestimates the cost-effectiveness of SCR at North Valmy.

Response 17: NDEP thanks the Conservation Organizations for their independent review of the cost effectiveness of SCR installation at North Valmy Generating Station. NDEP acknowledges the differences between Mr. Kordzi's report and those found in NV energy's four-factor analysis, including changes to the CEPCI, results in a lower SCR cost effectiveness estimate. NDEP requested NV Energy update its four-factor analysis to include the 2023 CEPCI value and requested clarification on its reagent cost (Appendix F). After reviewing NV Energy's responses to NDEP's request for additional information NDEP maintains that SCR's cost effectiveness does not meet the $10,000/ton threshold.

Comment 18: NDEP Should Require SCR as the Reasonable Progress Measure at North Valmy.

Response 18: NDEP acknowledges this comment and respectfully disagrees. NDEP acknowledges the differences between Mr. Kordzi's report and those found in NV energy's four-factor analysis. Most of these differences have a minor impact on the cost effectiveness of SCR with the notable exception of the estimated actual annual MWh output. While there have been variations in annual MWh output at North Valmy Generating Station since the 2016-2018 baseline, NDEP decided to retain the original baseline to maintain consistency with the baseline established in the SIP for the Regional Haze Round Second Planning Period. NDEP requested NV Energy update its four-factor analysis to include the 2023 CEPCI value and requested clarification on its reagent cost. After reviewing comments from the NPS, Conservation Organizations, and NV Energy's responses to NDEP's request for additional information (Appendix F) NDEP does not find that SCR's cost effectiveness meets the $10,000/ton threshold.

Tracy Generating Station

Comment 19: NDEP Does Not Ensure that Utilization of Units 5 and 6 Remain Low.

Response 19: NDEP acknowledges this comment and respectfully disagrees. This SIP Revision does not revise requirements and conclusion found in the 2022 Regional Haze SIP for Units 5 and 6 of the Tracy Generating Station. As NDEP stated in Appendix D.6 Response 11 of the 2022 Regional Haze SIP:

> When conducting a four-factor analysis for the North Valmy Generating Station, NDEP developed baseline emissions for Tracy Units 5 and 6 and determined both units had significantly low annual NO_X emissions equal to, or less than, 12 tons per year. With this information and reference to the EPA guidance, NDEP reasonably determined that the outcome of a four-factor

analysis would not result in cost-effective control measures, as the achievable emission reductions would be too low to produce a reasonable cost-effectiveness value, and removed these units from further consideration.

EPA's Guidance and Clarification Memo requires that states evaluate whether a unit's existing *measures* are necessary to make reasonable progress. That is, when states are relying on existing measures, the state must ensure that the source will continue to use those control measures, not continue to achieve the same level of utilization or annual emissions. Utilization varies, especially for electrical generating units. NDEP does not consider a unit's low utilization as an existing control measure that should be included in Nevada's long-term strategy. NDEP notes that the continued use of existing NO_X control measures (dry low NO_X combustors) at Tracy Units 5 and 6 were included in the SIP's long-term strategy as reasonable progress measures.

Comment 20: NDEP May Not Waive the BART Requirement that Unit 3 Operate SNCR.

Response 20: NDEP acknowledges this comment and recognizes that SNCR has not been installed on Tracy Unit 3. This SIP Revision does not revise requirements and conclusion found in the 2022 Regional Haze SIP or the 2009 Regional Haze SIP for Units 3 of the Tracy Generating Station. As NDEP stated in Appendix D.6 Response 14 of the 2022 Regional Haze SIP:

NDEP recognizes that SNCR has not been installed on Tracy Unit 3 and agrees that it is the state's responsibility to ensure that BART determinations, and limits, from the first round, are implemented and remain in compliance. However, NDEP disagrees that SNCR must be installed, or that a new NO_X limit should be evaluated that would reflect the use of SNCR. As stated in both the Nevada Administrative Code and Nevada's initial Regional Haze SIP, a BART control measure may be replaced or supplemented with alternative technologies approved in advance by the Director, provided that the emission limits are met. As outlined in Nevada's Regional Haze 5-Year Progress Report submitted on November 18, 2014, NV Energy achieved the set BART emission limit for Tracy Unit 3 with alternative technologies and was granted approval to not install SNCR. NV Energy still remains compliant with Tracy Unit 3's BART determination from the first round, and therefore, NDEP does not find it appropriate, or lawful, to force the facility to install SNCR or set a new NO_X limit that would require the source to install SNCR.

NDEP notes that SNCR was again evaluated as a potential control measure in Tracy Unit 3's four-factor analysis and was determined as not cost-effective or needed to achieve reasonable progress during this implementation period.

Comment 21: NDEP continues to incorrectly include a 4.6 percent sales tax in its cost effectiveness estimate.

Response 21: NDEP requested additional information from NV Energy to support the use of a 4.6 percent sales tax in its cost effectiveness estimate. NV Energy acknowledged that sales tax exemptions exist for emissions control equipment, however NRS 361.077(2) indicates that this exemption only applies to equipment whose primary purpose is compliance with existing laws or standards (Response to Comment 21, Appendix F.3). In this instance SCR represents a prospective alternative to improve visibility in nearby Class I areas rather than a system needed to comply with an existing emission standard. If the installation of SCR is found to qualify for the state sales tax exemption this would reduce the capital expenses by $141,491 and reduce the control cost effectiveness by $49.43 per ton of emission reduction.

Comment 22: NDEP continues to improperly include an engineering, procurement, and construction ("EPC") contract surcharge in its estimate.

Response 22: NDEP requested additional information from NV Energy to support the use of an EPC contract surcharge. NV energy replied that Section 2.6.4.2 of EPA's Control Cost Manual outlines key considerations for retrofitting new emission control systems on existing sources (Response to Comment 22, Appendix F.3). It describes the two most common project execution methods: design-build and design-bid-build. The section also clarifies that "design-build," and "EPC" are used interchangeably. Additionally, Section 2.4.1 states that "contractor fees" are part of a project's direct installation costs. Therefore, including an EPC contractor fee in the total capital cost estimate for installing an SCR system on Unit 4 at Tracy Station aligns fully with the methodology described in EPA's Control Cost Manual.

Comment 23: NDEP continues to assume, without support, a 90 percent control efficiency for SCR.

Response 23: NDEP acknowledges and thanks the Conservation Organizations for their comment. NDEP requested additional information from NV Energy documenting the NO_X emissions rates with SCR for Tracy Generating Station Unit 4 Piñon Pine (Request 5, Appendix F.1). As stated in the Updated Four Factor Analysis, Appendix B, Section 5.2, selective catalytic reduction (SCR) with 90% reduction would achieve 4.1 ppm @15% O2 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 (Fd-Factor) in units of dscf/10^6 Btu *
> 20.9/(20.9 – O2%), where:
>
> > NO_X ppm = 4.1
> > NO_X conversion factor = 1.194E-7 (Table 19-1)
> > Fd-Factor, natural gas = 8,710 (Table 19-2)
> > O2 = 15% (calculating at 15% O2)
>
> 4.1*1.194E-7*8,710*20.9/(20.9-15) = 0.0151 lb/MMBtu

Comment 24: NDEP still assumes a 47 month construction time frame, without any rationale or support.

Response 24: NDEP appreciates this comment. NDEP has included a compliance deadline of 36 months after SIP approval to install control measures, referenced in Table 1-1 of this Revision. NDEP approved a 12 month buffer to allow NV Energy to coordinate the upgrades at the Tracy Generating Station with upgrades being completed at the North Valmy Generating Station, and account for supply chain or other issues that may arise during the course of the permitting, procurement, and installation of the controls determined by the four-factor analysis.

Comment 25: The Four-Factor Analysis uses an incorrect and inflated CEPCI.

Response 25: NDEP agrees that the CEPCI value used by NV Energy in its four-factor analysis was not the finalized 2023 value as stated in Response 11 the value used was an unfinalized 2023 value which was available at the time the analysis was performed. NV Energy provided an updated cost estimate using the finalized 2023 CEPCI value (NV energy Response Letter 10, Appendix F.2). NDEP verified that the cost estimate for SCR is still above the $10,000/ton threshold.

Comment 26: NDEP uses an incorrect NO_X baseline for Unit 4 Piñon Pine.

Response 26: NDEP acknowledges this comment and recognizes that there is variability in NO_X emissions data at Tracy Generating Station from 2016 through 2024. NDEP decided to retain the original baseline to maintain consistency with the baseline established in the SIP for the Regional Haze Round Second Planning Period.

Comment 27: Correcting the Unit 4 Piñon Pine Four-Factor Analysis Yields an SCR Cost-Effectiveness Estimate Less Than Half of NDEP's Estimate.

Response 27: NDEP thanks the Conservation Organizations for their independent review of the cost effectiveness of SCR installation for Unit 4 Piñon Pine and acknowledges that changes to the CEPCI and the possible removal of sales tax, if the project is found eligible by Nevada law, results in a lower SCR cost effectiveness estimate. NDEP maintains that the cost effectiveness of SCR meets the $10,000/ton threshold.

Enforceability of Control Measures

Comment 28: The Permit Provisions NDEP Proposes to Incorporate into the SIP Are Not Practically Enforceable.

Response 28: NDEP agrees that emission reductions needed to make reasonable progress must be included as practically enforceable SIP measures. All forms of emission reductions are practically enforceable through provisions listed in the source's state-issued permits and regulation R138-24. NDEP has confirmed that regulation R138-24 and all state-issued permit provisions relied upon to make reasonable progress have been directly incorporated by reference into the SIP. Upon EPA's approval of the SIP, these emission limitations, along with all other requirements needed to ensure practical enforceability, will be made permanent and federally enforceable.

NDEP provided emissions limitations and associated requirements for all reasonable progress measures in the draft SIP made available for public review. As part of the associated requirements, continuous emissions monitoring systems (CEMS) are used to determine compliance for all reasonable progress measures. CEMS requirements have been listed as an admissible form of credible evidence in EPA's 1997 Credible Evidence Revision. NDEP has incorporated by reference R138-2 and all permit provisions relevant to CEMS requirements needed to determine compliance and ensure practical enforceability of the specific emission limitations.

Uniform Rate of Progress Glidepath

Comment 29: NDEP's Glidepath Adjustment for Jarbidge Does Not Satisfy the Purpose and Requirements of the Regional Haze Program.

Response 29: NDEP acknowledges this comment and respectfully disagrees that the Glidepath Adjustment for Jarbidge does not satisfy the purpose and requirements of the Regional Haze Program. In accordance with 40 CFR 51.308(f)(1)(vi)(B), NDEP proposes in its SIP to adjust the uniform rate of progress glidepath for Jarbidge Wilderness Area to account for international and prescribed fire impacts. This decision was made to provide a more accurate representation of what emissions, and subsequent visibility impacts, fall under the regulatory scope of state and federal agencies. Furthermore, NDEP did not rely on 2028 Reasonable Progress Goals (RPGs) that fall below the URP glidepath as a "safe-harbor" to not require any reasonable progress measures. NDEP still conducted robust four-factor analyses for several sources across the state and thoroughly considered the four statutory factors when making reasonable progress determinations.

Appendix H – Proof of Legal Authority to Adopt, Revise and Submit SIPs

ALLEN BIAGGI
Director

JIM GIBBONS
Governor

KAY SCHERER
Deputy Director

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Division of State Lands
Division of State Parks
Division of Water Resources
Natural Heritage Program
Wild Horse Program

STATE OF NEVADA
Department of Conservation and Natural Resources
OFFICE OF THE DIRECTOR

May 30, 2007

Wayne Nastri
Regional Administrator
ORA-1, USEPA Region 9
75 Hawthorne Street
San Francisco CA 94105

Dear Mr. Nastri:

Nevada Revised Statutes 445B.205 designates the Department of Conservation and Natural Resources (Department) as the air pollution control agency for the State of Nevada for the purposes of the Clean Air Act insofar as it pertains to State programs. Within the Department, the Division of Environmental Protection has responsibility to manage the air quality planning and air pollution control programs for the State of Nevada. Therefore, pursuant to Nevada Administrative Code 445B.053, I am hereby assigning the Administrator of the Nevada Division of Environmental Protection, or the Deputy Administrator acting on his behalf, to be my official designee for the purposes of the Clean Air Act, including, but not limited to, adoption, revision and submittal of state plans and state implementation plans.

Sincerely,

Allen Biaggi
Director

cc Michael Dayton, Chief of Staff, Office of the Governor
Jodi Stephens, Deputy Chief of Staff, Office of the Governor
Leo Drozdoff, Administrator, NDEP
Colleen Cripps, Deputy Administrator, NDEP
Tom Porta, Deputy Administrator, NDEP
Deborah Jordan, Director, EPA Air Division, Region IX
Jefferson Wehling, ORC, EPA Region IX