Appendix B.1.c - LNA Email

RE: RHR Apex Plant Update

ANDREWS Justin <Justin.ANDREWS@lhoist.com>

Wed 3/9/2022 11:03 AM

To: Steven McNeece <smcneece@ndep.nv.gov>

Cc: Sigurd Jaunarajs <sjaunara@ndep.nv.gov>; Richard Beckstead <Beckstead@ClarkCountyNV.gov>

Hi Steven,

Yes – I see your point that the last analysis did not include the 10% reduction from utilizing a LNB on Kiln 3 (the LNB was installed after the baseline period and was not accounted for). Looking at your new NOx Limit table, the total NOx reduction from all kilns would be 506.09 TPY. If I subtract this from the current combined kiln allowable NOx limit (1,874 TPY) and divide by the combined kiln allowable production (840,000 TPY), I get a limit of 3.26 lb NOx/ton of lime produced.

In regards to your question related to the increased limit.....this was related to the fact that many times we are not able to operate each kiln at full production. As an example, instead of operating Kiln 4 at the allowable production rate of 1,350 tons per day, we may have to restrict the kiln to a lower production rate (potentially 1,000 TPD) due to customer demand and/or available space in storage silos. During these instances of reduced production, the kiln does not operate as efficiently. The fuel to lime production rate is not a linear relationship. During periods of reduced lime production, we will likely see a reduction in the total NOx emissions (tons), but the lb NOx per ton of lime produced will increase. For this reason, we gave ourselves a 10% margin in the allowable lb/tlp emission rate. 3.29 lb/tlp x 1.1 = 3.62 lb/tlp. With the revised calculation for the Kiln 3 LNB, this would now change to 3.26 lb/tlp x 1.1 = 3.59 lb/tlp across all operating kilns.

Please give me a call if you would like to discuss this further. Also, can you tell me what the expected timeframe is for finalizing these emission limits? We have a Title V renewal application that is due next month. Would it make sense to try to update the permit with that revision?

Regards

Justin Andrews
Regional Environmental Manager – West
702-236-1409

From: Steven McNeece <smcneece@ndep.nv.gov>
Sent: Tuesday, March 8, 2022 9:35 AM
To: ANDREWS Justin <Justin.ANDREWS@lhoist.com>
Cc: Sigurd Jaunarajs <sjaunara@ndep.nv.gov>; Richard Beckstead <Beckstead@ClarkCountyNV.gov>
Subject: Re: RHR Apex Plant Update

Previous attachment was no good. This one should work.

Steven

From: Steven McNeece <smcneece@ndep.nv.gov>
Sent: Tuesday, March 8, 2022 9:33 AM
To: Justin.ANDREWS <Justin.ANDREWS@lhoist.com>
Cc: Sigurd Jaunarajs <sjaunara@ndep.nv.gov>; Richard Beckstead <Beckstead@ClarkCountyNV.gov>
Subject: Re: RHR Apex Plant Update

Hey Justin,

I hope you are doing well! We're hoping to finalize the proposed NOx limits and associated requirements for Regional Haze controls so we can move forward with revising the Apex Plant permit soon. However, I noticed a small error in the proposed NOx limits you provided for us in the email below. Since the baseline emissions we are using for these calculations come from 2016-2018 data, it doesn't include the assumed 10% reduction from the LNB that was installed on Kiln 3 in 2019. I adjusted the calculations to reflect this in the spreadsheet attached in this email. The difference is insignificant, but we want to make sure we're accounting for all assumed reductions. Feel free to take a look at the new calculations and please let me know what you think.

Additionally, can you provide further explanation on the proposed 3.62 lb/tlp limit? More specifically, how you came to this value in comparison to the calculated 3.29 lb/tlp. Note, that the new calculations in the spreadsheet now show 3.25 lb/tlp.

Thanks so much and happy to discuss further if you'd like,
Steven

From: ANDREWS Justin <Justin.ANDREWS@lhoist.com>
Sent: Monday, September 13, 2021 7:49 PM
To: Steven McNeece <smcneece@ndep.nv.gov>
Subject: RE: RHR Apex Plant Update

Steven,

I apologize for the delay in getting back to you. LNA has evaluated the proposed emission reductions on Kilns 1, 3, and 4 at Apex and is proposing the following facility-wide (i.e. Kilns 1, 2, 3, and 4) emission limits. These emission limits closely resemble those approved for the LNA Nelson Plant during the first round of Regional Haze.

1. **3.78 tons per kiln operating day** based on a 30-day rolling average. Total tons of NOx from all operating kilns would be totaled on a daily basis. Each days total would be averaged over 30 days and compared to the 3.78 TPD emission limit. If no kilns operated on a particular day, the day would be skipped when calculating the 30-day average.
2. **3.62 lb / ton of lime produced** based on a 12-month rolling average. Total pounds of NOx from all operating kilns would be totaled for each calendar month and divided by the total tons of lime produced to determine the monthly rate. Each monthly rate would be used in the average to determine the 12-month rolling average. You will notice the 3.62 lb/tlp emission limit is higher than the calculated value shown in the table below (3.29 lb/tlp). This is to account for production variability and inefficiencies in circumstances where demand does not account for the full allowable production rate. I am happy to discuss this further with you if necessary.

	Current Limits			Regional Haze Reductions			
	Production (tpy)	NOx (tpy)	NOx (lb/tlp)	NOx Reduction (tpy)	NOx (tpy)	NOx (tpd)	NOx (lb/tlp)
Kiln 1	109,500	343	6.27	85	258	0.71	4.72
Kiln 2	109,500	350	6.39	0	350	0.96	6.39
Kiln 3	146,000	478	6.55	30	448	1.23	6.14
Kiln 4	475,000	702	2.96	378	324	0.89	1.36
Total	840,000	1,874	4.46	493	1,381	3.78	3.29

In regards to the timing of implementation of controls, LNA has already installed low-NOx burners on Kilns 3 and 4. A low-NOx burner would still be required for Kiln 1 and SNCR would be required for Kilns 1, 3, and 4. LNA expects a minimum of two years would be needed to properly design, construct, and optimize additional controls from the time a permit condition requiring the additional controls became enforceable. Applicable emission rates would first be calculated 30-days and 12-months after, as applicable.

Please let me know if you have any questions regarding the proposed emission limits and controls implementation.

Regards,

Justin Andrews
Regional Environmental Manager – West
702-236-1409

From: Steven McNeece <smcneece@ndep.nv.gov>
Sent: Monday, August 30, 2021 12:49 PM
To: ANDREWS Justin <Justin.ANDREWS@lhoist.com>
Subject: Re: RHR Apex Plant Update

Hi Justin,

Just wanted to reach out and see if you had a status update on Lhoist's latest submittal?

Thanks!
Steven

From: Steven McNeece <smcneece@ndep.nv.gov>
Sent: Monday, August 2, 2021 7:39 AM
To: Justin.ANDREWS <Justin.ANDREWS@lhoist.com>
Subject: Re: RHR Apex Plant Update

Hi Justin,

Sure, mid-August will be fine.

Thanks!
Steven

Appendix B.1.d - LNA Comments

October 13, 2021

Mr. Steven McNeece
Nevada Division of Environmental Protection
901 South Stewart Street, Suite 4001
Carson City, NV 89701
Via electronic submission (smcneece@ndep.nv.gov)

RE: Lhoist North America of Arizona, Inc. – Apex Plant
Comments on Draft 2021 Regional Haze Four Factor Review and Initial Control Determination

Dear Mr. McNeece,

Lhoist North America of Arizona, Inc. (LNA) owns and operates the Apex Plant (Facility) located in Clark County, Nevada. The Facility is in receipt of the draft 2021 Regional Haze Four Factor Review and Initial Control Determination (Report) issued by the Nevada Division of Environmental Protection (NDEP). Overall, LNA agrees with NDEP on the control determination and NO_X emission limits that have been proposed; however, LNA has the following comments for NDEP's consideration.

- Page 3, Section 2 – The Report states that LNA operates four horizontal coal-fired rotary preheater lime kilns. Each of the four kilns is permitted to utilize coal, petroleum coke, and/or natural gas in the production of lime.
- Page 3, Section 3 – The Report indicates that a Low NO_X Burner (LNB) was installed on Kiln 3 in August of 2019. Should NDEP also reference the LNB that was installed on Kiln 4 in April of 2021? The Kiln 4 LNB is referenced in later sections of the Report.
- Page 11, Section 8 – The Report states that NDEP will rely on the existing monitoring, recordkeeping, and reporting requirements outlined in the source's Clark County Department of Environment and Sustainability (CCDES) operating permit. CCDES's current emission reporting guidance for Kilns 1, 2, and 3 requires that kiln specific NO_X emissions be calculated on an annual basis using the potential to emit (PTE) emission factor. If LNA utilizes the Regional Haze allowable emission rate for Kilns 1, 2, and 3 to determine compliance, there is little reason in having a site wide emission limit. As Kiln 4 is the only measured source, the site wide emission limits will be achieved as long as Kiln 4 meets the Regional Haze source specific emission rate. It is important that the methodology for determining compliance be clear and defined as part of the Regional Haze rule making process. LNA would like to propose the following process for determining compliance with the Regional Haze emission limits.
    - o 3.78 tons per rolling 30-kiln-operating-day average. Each rolling 30-kiln-operating-day average will be calculated per the following procedure:
        1. Step One. Sum the hourly pounds of NO_X emitted from Kilns 1, 2, 3, and 4 for the current kiln-operating-day and the preceding 29 kiln-operating-day period.
            - For Kilns 1, 2, and 3, daily NO_X emissions will be calculated based on a measured, source specific, NO_X emission factor (lb NO_X per ton of lime

produced). Kilns that operate more than 4,380 hours in the previous calendar year will conduct a NO_X emissions test in the current year to update the emission factor. Kilns that operate less than 4,380 hours in the previous calendar year will rely on the previously determined emission factor for the source.

- For Kiln 4, NO_X emissions will be measured utilizing CEMS. During periods of CEMS downtime, NO_X emissions will be estimated using the existing data substitution plan.

2. Step Two. Divide the total pounds of NO_X calculated from Step One by 2000 to calculate the total tons of NO_X emitted over the most recent 30-kiln-operating-day period.
3. Step Three. Divide the total tons of NO_X calculated from Step Two by 30 to calculate the rolling 30-kiln-operating-day NO_X emission rate from all kilns.

- 3.62 lb / ton of lime produced (tlp) based on a 12-month rolling average. Each 12-month rolling NO_X emission rate will be calculated within 30 days following the end of each calendar month per the following procedure:

1. Step One. Sum the hourly pounds of NO_X emitted from each kiln for the month just completed and the 11 months preceding the month just completed to calculate the total pounds of NO_X emitted over the most recent 12-month period.

    - For Kilns 1, 2, and 3, NO_X emissions will be calculated based on a measured, source specific, NO_X emission factor. Kilns that operate more than 4,380 hours in the previous year will conduct a NO_X emissions test in the current year to update the emission factor. Kilns that operate less than 4,380 hours in the previous year will rely on the previously determined emission factor for the source.
    - For Kiln 4, NO_X emissions will be measured utilizing CEMS. During periods of CEMS downtime, NO_X emissions will be estimated using the existing data substitution plan.

2. Step Two. Sum the total lime production, in tons, produced from Kilns 1, 2, 3, and 4 during the month just completed and the 11 months preceding the month just completed 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.
3. Step Three. Divide the total pounds of NO_X calculated from Step One by the total tons of lime product calculated from Step Two to calculate the 12-month rolling NO_X emission rate in lb/tlp.

- Page 11, Section 8 – The Report indicates the Facility should be in compliance with the required emission control systems prior to August 1, 2024. LNA proposes a compliance deadline of August 1, 2024, or two years after the Regional Haze control requirements are included in a federally enforceable operating permit, whichever is later.

LNA appreciates NDEP's consideration of these comments. If you have any questions concerning the comments listed above, please contact me at (702) 236-1409 or justin.andrews@lhoist.com.

Sincerely,

Justin Andrews
Regional Environmental Manager - West

CC: Sean Brennan (LNA)
Terry Hunsicker (LNA)
Chris Scholl (LNA)

Appendix B.2 - Pilot Peak Plant, Graymont Western

Appendix B.2.a	NDEP Reasonable Progress Determination for Pilot Peak Plant
Appendix B.2.b	Graymont Western Four-Factor Analysis for Pilot Peak Plant
Appendix B.2.c	Response Letter 1
Appendix B.2.d	Response Letter 2
Appendix B.2.e	Response Letter 3

Appendix B.2.a - NDEP Reasonable Progress Determination for Pilot Peak Plant

Pilot Peak Plant Reasonable Progress Control Determination

Evaluation of existing and potential new control measures at Graymont Western's Pilot Peak Plant necessary to achieve reasonable progress for Nevada's second Regional Haze SIP.

Bureau of Air Quality Planning, Nevada Division of Environmental Protection

June 2022

1 Introduction

This document serves as the official reasonable progress determination for the Pilot Peak Plant based on analyses submitted by the owner of the facility. The Long-Term Strategy of Nevada's Regional Haze SIP revision for the second implementation period covering years 2018 through 2028 will rely on the reasonable progress findings of this document.

This reasonable progress determination references data and analyses provided by Graymont Western (GW) in several documents that can be found in Appendix B.2. Table 1-1 below outlines the documents submitted by GW that supplement this determination document. In some cases, the Nevada Division of Environmental Protection (NDEP) adjusted information submitted by GW to ensure the analyses relied on to make reasonable progress determinations agree with Regional Haze Rule regulatory language, Regional Haze Rule Guidance for the second implementation period, and EPA's Control Cost Manual. Throughout the document, it can be assumed that referenced data and information rely on the following documents submitted by GW, unless explicitly indicated that NDEP made adjustments.

Table 1-1: GW Documents Relied upon for Reasonable Progress Determination

Full Document Title	Shortened Document Title (used in this document)	Date	Appendix Location
Reasonable Progress Four-Factor Analysis	*GW Analysis*	October 2020	B.2.b
RE: Graymont Pilot Peak Response to Federal Land Managers Comments on Four-Factor Analysis for Regional Haze	*Response Letter 1*	November 13, 2020	B.2.c
RE: Pilot Peak Response to NDEP Request for Additional Information Graymont Western US, Inc.	*Response Letter 2*	April 16, 2021	B.2.d
RE: Graymont Pilot Peak Response to the Initial Control Determination Letter	*Response Letter 3*	October 15, 2021	B.2.e
Class I Air Quality Operating Permit	Permit		A.2

2 Facility Characteristics

As stated on page 3-1 of the *GW Analysis*:

"The Graymont Western US, Inc. Pilot Peak Plant is located in Elko County, Nevada, approximately 10 miles northwest of West Wendover. The nearest Class I area to the plant is the Jarbidge Wilderness Area. It is approximately 130 kilometers northwest of the Pilot Peak plant.

The facility operates three horizontal rotary preheater lime kilns. The three kilns are nearly identical in design and operations, although the production rates for each kiln vary. Kilns 1, 2, and 3 are permitted for producing lime at a rate of 25, 33.3, and 50 tons per hour, respectively.

All three kilns use coal as a primary fuel source. Typical annual fuel usage rates for the three kilns combined are approximately 130,000 tons per year of coal (at approximately 11,600 Btu/lb). Fuels typically used for kiln startup include diesel and propane. Natural gas is not available at the plant."

3 Emissions Profile

3.1 Q/d Emissions Profile

NDEP relied on the Q/d method for source selection by quantifying total facility-wide NO_x, SO_2, and PM_{10} emissions, represented as "Q", reported in the 2014 NEIv2. The Q value was then divided by the distance, in kilometers, between the facility and the nearest Class I area (CIA), represented as "d". The nearest CIA to the Pilot Peak Plant is Jarbidge Wilderness Area at 131 kilometers away. NDEP elected to set a Q/d threshold of 5. As displayed in Table 3-1, using 2014 NEIv2 emissions, the Pilot Peak Plant yielded a Q/d value of 5.15, effectively screening the facility into a four-factor analysis requirement for the second round of Regional Haze in Nevada.

Table 3-1: Original Pilot Peak Plant Q/d Derivation

NO_x Emissions (tpy)	SO_2 Emissions (tpy)	PM_{10} Emissions (tpy)	Total Q (NO_x+SO_2+ PM_{10})	Distance from Nearest CIA (Jarbidge WA) [km]	Q/d
523	23	127	673	131	**5.15**

These emissions were pulled from the 2014 NEIv2, based on NO_x emission rates presented in Table 3-2, however, in *Response Letter 2*, Graymont indicated that the emissions reported in the 2014 NEIv2, particularly the NO_x emissions, did not agree with what was submitted by Graymont for Pilot Peak's 2014 Annual Emission Inventory (AEI). Graymont's AEI for Pilot Peak in 2014 resulted in a Total Q of 604 tons per year (tpy), rather than 673, resulting in a Q/d of 4.61 (see Table 3-3). The change in resulting Total Q is primarily due to different NO_x emission rates used to calculate total NO_x emissions. Table 3-4 shows Graymont's calculated NO_x emissions for 2014 to be compared to Table 3-2 that outlines NDEP's calculation that was incorporated into the 2014 NEIv2.

As seen in Table 3-2, NDEP calculated NO_x emissions for the Pilot Peak Plant kilns in 2014 using a NO_x emission rate in pound per hour, multiplied by the annual hours of operation for each kiln. This produced facility-wide NO_x emissions at 523 tons per year, resulting in a Q/d of 5.15. Alternatively, as seen in Table 3-4, Graymont calculated NO_x emissions for the Pilot Peak kilns in 2014 using a NO_x emission rate in pounds of NO_x per ton of lime produced, multiplied by the annual lime production rate for each kiln in tons per year. This produced facility-wide NO_x emissions at 459 tons per year, resulting in a Q/d of 4.61.

Table 3-2: NDEP-Calculated NO_x Emissions for Pilot Peak in 2014

Unit	NO_x Emission Rate (lb/hr)	Hours of Operation (hr/yr)	NO_x Emissions (tpy)
Kiln 1	47.5	7033	167
Kiln 2	40.1	7033	141

Kiln 3	60.2	7153	215
		Total NO_x Emissions	**523**

Table 3-3: Updated Pilot Peak Plant Q/d Derivation

NO_x Emissions (tpy)	SO_2 Emissions (tpy)	PM_{10} Emissions (tpy)	Total Q (NO_x+SO_2 +PM_{10})	Distance from Nearest CIA (Jarbidge WA) [km]	Q/d
459	23	122	604	131	**4.61**

Table 3-4: Graymont-Calculated 2014 NOx Emissions for Updated Q/d

Unit	NO_x Emission Rate (lb NO_x/ton lime)	Lime Production Rate (tons/yr)	NO_x Emissions (tpy)
Kiln 1	2.102	125,313	131.69
Kiln 2	1.302	199,362	129.78
Kiln 3	1.374	287,132	197.32
		Total NO_x Emissions	**459**

NDEP has reviewed the reporting requirements for NO_x emissions in the Pilot Peak Plant's air quality operating permit and confirms that the permitted procedure is to calculate NO_x emissions for each kiln using NO_x emission rates in pounds of NO_x per ton of lime produced, and annual lime production rates in tons per year. Because of this, Graymont no longer places above the set Q/d threshold of 5 and, therefore, is formally screened out of a four-factor analysis requirement and is not considered further for potential new control measures.

A comparison to other reporting years, and their resulting Q/d values, were conducted for years 2015 through 2020. As shown in Table 3-5, the following four operating years (2015-2018) also yield Q/d values below 5, while 2019 and 2020 yield a Q/d value above 5.

Table 3-5: Q/d Comparison Among Operating Years at Pilot Peak Plant

	Facility Emissions (tpy)						
Pollutant	**2014***	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
NO_x	459	406	451	395	418	562	700
SO_2	23	25	15	15	18	19	18
PM_{10}	122	66	75	70	68	77	80
Total	**604**	**497**	**541**	**480**	**504**	**658**	**798**
Q/d	**4.61**	**3.79**	**4.13**	**3.66**	**3.85**	**5.02**	**6.09**

*Updated 2014 emissions submitted in Graymont's AEI

Although emissions reported in 2019 and 2020 yield Q/d values above 5, NDEP does not find that it is reasonable to screen the source back into a four-factor analysis requirement for consideration of potential new measures for the following reasons:

1. Arbitrary Action – NDEP is reluctant to hold the Pilot Peak Plant to a different reporting year than other sources for source selection, as this can be seen as an arbitrary action. All other sources in the state of Nevada were considered for source selection using 2014 emissions, Pilot Peak would be the sole facility that was held to a different reporting year.
2. Emission Inventories – the majority of WRAP states agreed to conduct source selection through the Q/d analysis using emissions from the NEI so emissions for all Western States could be easily accessed and reviewed by the Western Regional Air Partnership (WRAP) States and members. WRAP agreed to rely on the 2014 NEIv2 for source selection. This was done so that the Representative Baseline emission inventory (based on years 2014-2018) used in the SIP would agree with emissions used for source selection. At the time source selection was conducted, in August of 2019, 2017 and 2020 NEI were not yet available. Even if NDEP elected to rely on 2017 NEI emissions for source selection when it was released, Graymont would have had a Q/d of 3.66. The 2020 NEI is still not yet available.
3. Overall Q/d - considering Q/d values for 2014 through 2020, five of the seven years, or clear majority, show a Q/d value below NDEP's set threshold. The average Q/d across all seven years is 4.45, also falling below the threshold of 5.

Graymont did not provide updated 2014 emissions, subsequently screening them out of the four-factor requirement, until after they had already provided source information for a four-factor analysis (*GW Analysis*). Graymont has volunteered to include all information submitted for a four-factor analysis to demonstrate their efforts in remaining compliant with the requirements of the Regional Haze Rule, but do not intend for the submitted information to be used to consider new potential control measures for the second implementation period of the Regional Haze Rule in Nevada.

Although no new measures were formally considered to achieve reasonable progress at the Pilot Peak kilns, NDEP still evaluated whether any existing measures at the facility were necessary to achieve reasonable progress, outlined in the following sections.

4 PM_{10} Determination for Existing Measures

The following statement found on page 7-1 of the *GW Analysis* describes the existing control measures implemented at the Pilot Peak Plant kilns to control PM_{10} emissions:

"The use of a baghouse for control of PM_{10} from lime kilns is consistent with current BACT determinations. RBLC search results are provided in Appendix A, for reference. The average baseline emission factor for Kiln 3 of 0.057 lb/ton of lime is lower than even the lowest emission limit listed in the RBLC database. While the emission factors for kilns 1 and 2 are higher for 2013 and 2014 (at 0.272 and 0.255 lb/ton, respectively), more recent PM_{10} stat test data following replacements of the Kilns 1 and 2 baghouses indicate that emissions from those kilns are also lower than recent limits in the RBLC database. For consistency with NO_x and SO_2 evaluations, the emission rates and factors for 2013 and 2014 are listed. Based on these calculated emission rates, Pilot Peak kilns operate with a comparable or better level of PM_{10} emissions controls than those recently permitted under the PSD BACT program."

4.1 Weight-of-Evidence Demonstration

NDEP is relying on the following weight-of-evidence demonstration to conclude that the source's existing measures to control PM_{10} emissions are not necessary to achieve reasonable progress during the second implementation period of the Regional Haze Rule in Nevada.

4.1.1 Historical Emission Rates

The following annual PM_{10} emission rates were reported by Graymont for all three kilns at the Pilot Peak Plant from 2015 through 2020, representing data from the most recent six operating years (see Table 4-1). As stated above, baghouses were replaced on Kilns 1 and 2 shortly after 2014, so emissions data from 2013 and 2014 are excluded from the table. Aside from Kiln 1 in 2016, which shows an increase in PM_{10} emission rate, the reported PM_{10} emission rates at the Pilot Peak kilns show consistently low emission rates. The most recent four years, 2017-2020, and 2015, show a consistent PM_{10} emission rate for Kiln 1. NDEP considers the trend in PM_{10} emission rates in Table 4-1 as reasoning to assume that the source's achievable emission rates will remain consistent and not increase in the future.

Table 4-1: Historical PM_{10} Achievable Emission Rate Profile for Pilot Peak Kilns

	Reported Annual PM_{10} Emission Rates (lbs/ton-lime production)						
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2015-2020 Average**
Kiln 1	0.048	0.119	0.027	0.025	0.022	0.020	0.043
Kiln 2	0.010	0.044	0.029	0.029	0.042	0.030	0.031
Kiln 3	0.030	0.011	0.028	0.003	0.013	0.035	0.020

4.1.2 Projected Emission Rates

There are no federally enforceable on-the-way controls or changes to operations at the Pilot Peak Plant. Because of this, NDEP finds it reasonable to rely on emissions and emission rates calculated from the 2015-2020 representative historical period to project future emissions and emission rates. As stated in Table 4-1, the representative historical period, and projection assumption, for PM_{10} emission rates at Kilns 1, 2, and 3, are 0.043, 0.031, and 0.020 pounds per ton of lime produced, respectively. NDEP concludes that the projected emission rates will remain consistent with historical emission rates.

Table 4-2 outlines the facility-wide PM_{10} emissions reported from 2015 through 2020, along with the annual average among the evaluated years. NDEP is relying on the 2015-2020 average annual emissions to represent projected facility-wide emissions and concludes that the projected PM_{10} emissions of 73 tons per year will remain consistent with historical PM_{10} emissions.

Table 4-2: Historical Facility-Wide PM_{10} Emissions Profile for Pilot Peak Kilns

Reported Annual Facility-Wide PM_{10} Emissions (tons per year)						
2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2015-2020 Average**
66	75	70	68	77	80	73

4.1.3 Enforceable Emission Limits

NDEP is citing the following enforceable emissions limits listed in the facility's current air quality operating permit (AP3274-13329.03) to control PM_{10} emissions that reflect the source's existing measures as evidence that the source will continue to implement the use of baghouses at all three kilns.

Table 4-3: Enforceable PM_{10} Emission Limits

Unit ID	Unit Name	PM_{10} Emission Limit	
System 10	**Kiln #1 Circuit**	**13.6** lb/hr	**59.6** tons per 12-month rolling period
System 13	**Kiln #2 Circuit**	**15.2** lb/hr	**66.6** tons per 12-month rolling period
System 17	**Kiln #3 Circuit**	**23.7** lb/hr	**103.8** tons per 12-month rolling period

5 SO_2 Determination for Existing Measures

The following statement found on page 5-2 of the *GW Analysis* describes the existing control measures implemented at the Pilot Peak Plant kilns to control SO_2 emissions:

"SO_2 is inherently scrubbed within a lime kiln system due to the presence of large volumes of alkaline materials in the system, including limestone in the preheater that all kiln exhaust gases pass through. A typical kiln system scrubs approximately 90% of SO_2 (originating from both fuel sulfur and raw material sulfur) that would otherwise leave the stack. This in-situ scrubbing mechanism is commonly determined as BACT for preheater rotary kilns being permitted today. Dry sorbent injection operates under a similar principle, using the injection of lime particulate into the process stream to initiate the same reaction. Dry sorbent injection is not considered an available control methodology, because the reaction is already taking place inherently as part of the lime kiln process."

5.1 Weight-of-Evidence Demonstration

NDEP is relying on the following weight-of-evidence demonstration to conclude that the source's existing measures to control SO_2 emissions are not necessary to achieve reasonable progress during the second implementation period of the Regional Haze Rule in Nevada.

5.1.1 Historical Emission Rates

The following annual SO_2 emission rates were reported by Graymont for all three kilns at the Pilot Peak Plant from 2015 through 2020, representing data from the most recent six operating years. The Pilot Peak Plant kilns utilize a continuous emission monitoring system (CEMS) in tracking and reporting SO_2 emissions from each kiln. Table 5-1 outlines the annual SO_2 emissions reported for each kiln from 2015 through 2020, including average emissions for each kiln over the same years to serve as a representative historical emission rate. NDEP considers the annual SO_2 emission rates in tons per year recorded over the most recent six operating years as reasoning to assume that emission rates will remain consistent.

Table 5-1: Historical SO_2 Achievable Emission Rate Profile for Pilot Peak Kilns

	Reported Annual SO_2 Emission Rates (tons per year)						
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2015-2020 Average**

Kiln 1	2.41	1.93	1.18	1.19	2.49	2.40	1.93
Kiln 2	5.17	4.92	3.49	5.15	6.69	5.22	5.11
Kiln 3	17.09	8.19	8.99	11.61	10.00	10.43	11.05
Total	24.67	15.04	13.66	17.96	19.18	18.06	18.09

5.1.2 Projected Emission Rates

There are no federally enforceable on-the-way controls or changes to operations at the Pilot Peak Plant. Because of this, NDEP finds it reasonable to rely on emissions and emission rates calculated from the 2015-2020 representative historical period to project future emissions and emission rates. As stated in Table 5-1, the representative historical period, and projection assumption, for SO_2 emission rates at Kilns 1, 2, and 3, are 1.93, 5.11, and 11.05 tons per year, respectively. NDEP concludes that the projected emission rates will remain consistent with historical emission rates.

5.1.3 Enforceable Emission Limits

There are no enforceable emissions limits listed in the facility's current air quality operating permit (AP3274-1329.03) that reflect the use of "inherent scrubbing" as an SO_2 control measure.

6 NO_x Determination for Existing Measures

All kilns operating at the Pilot Peak Plant control NO_x emissions through the use of Low-NO_x Burners. These burners were installed in 2014, however, have not been incorporated into the source's air quality permit, along with associated NO_x emission limits that reflect the control efficiency of the burners. NDEP is relying on the continued use of Low-NO_x Burners on Kilns 1, 2, and 3 at the Pilot Peak Plant to achieve reasonable progress during the second implementation period of the Regional Haze Rule in Nevada.

7 Reasonable Progress Requirements

As stated above, NDEP does not find existing measures to control PM_{10} and SO_2 emissions as necessary to achieve reasonable progress during the second implementation period of the Regional Haze Rule in Nevada.

NDEP proposes the following the NO_x emission limitations, and other associated requirements, to be incorporated into the facility's air quality operating permit (AP3274-1329.03) as federally enforceable conditions.

7.1 Emission Limit

In setting new NO_x emission limits at all three Pilot Peak kilns to reflect the use of existing Low-NO_x Burners, NDEP is proposing the following:

The average of NO_x emissions reported for each kiln from 2013 to 2020 were used to develop a new NO_x emission limit to reflect the use of existing Low-NO_x Burners. Three standard deviations (sigma) were applied to the average NO_x emission limit for each kiln to establish a 99.7% confidence level in compliance. Although high, 99.7% still allows for at least one day of noncompliance per year. To combat this, an additional 10% of the original NO_x limit is also added. The below tables outline the emissions data reported in stack testing for the facility and the derivation of the new NO_x limits. This method is commonly and widely accepted as a means of establishing permit limits and the NDEP believes it provides a reasonable degree of compliance assurance.

NO_x Emission Rates (lb/hr) from Stack Test Data

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021
Kiln 1	43.50	47.50	40.00	57.60	44.90	44.61	43.00	74.18	85.41
Kiln 2	60.40	40.10	51.50	35.56	34.99	37.21	57.70	90.16	65.79
Kiln 3	58.30	60.20	44.40	67.12	74.05	89.53	102.4	108.1	94.62

Derivation of New NO_x Limits

Kiln	Average Stack Test Rate 2013-2021 (lb/hr)	Standard Deviation	New NO_x Emission Limit Ave + 3 St. Dev (lb/hr)	Previous NO_x Emission Limit (lb/hr)	Emission Limit Reduction
1	53.4	16.0	101.4	120	15.5 %
2	52.6	18.3	107.4	160	32.9 %
3	77.6	22.0	143.7	200	28.2 %

7.2 Averaging Period

For Kiln 1, the discharge of NO_x to the atmosphere shall not exceed 101.4 pounds per hour over a 30-day rolling average.
For Kiln 2, the discharge of NO_x to the atmosphere shall not exceed 107.4 pounds per hour over a 30-day rolling average.
For Kiln 3, the discharge of NO_x to the atmosphere shall not exceed 143.7 pounds per hour over a 30-day rolling average.

7.3 Compliance Deadline

All three kilns must comply with these new NO_x emission limits once CEMS is installed and operating no later than 270 days after permit issuance.

7.4 Monitoring, Record Keeping, and Reporting Requirements

The new emission limit and averaging period will be implemented and enforced through the source’s existing record keeping and reporting requirements outlined in the AQ operating permit. NO_x emission rates for each kiln will be monitored using a Continuous Emission Monitoring System (CEMS). CEMS monitoring NO_x emissions at each kiln must be installed and operating by the applicable compliance date (240 days).

Appendix B.2.b - Graymont Western Four-Factor Analysis for Pilot Peak Plant

REASONABLE PROGRESS FOUR-FACTOR ANALYSIS

GRAYMONT WESTERN US INC.> Pilot Peak, NV

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1. EXECUTIVE SUMMARY

This report documents the results of a four-factor control analysis for the Graymont Western US Inc. (Graymont) Pilot Peak lime plant, which is located near West Wendover, Nevada. This report is provided in response to the Nevada Department of Environmental Protection (NDEP) request letter dated August 12, 2019.

Graymont was not identified as an eligible facility for the best available retrofit technology (BART) program during the first round of regional haze as it was built after August 7, 1977. NV DEP has identified the Pilot Peak plant as an eligible source for the regional haze program reasonable progress analysis based on a screening process that takes into account both the quantity of emissions from the facility and the proximity to the Class I areas protected by the regional haze program.

The U.S. EPA's guidelines in 40 CFR Part 51.308 are used to evaluate control options for the lime kilns. In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these four factors are taken into consideration in selecting the goal (40 CFR 51. 308(d)(1)(i)(A)).

The purpose of this report is to provide information to NDEP regarding potential SO_2, NO_X, and PM_{10} emission reduction options for the Graymont Pilot Peak lime kilns. Based on the Regional Haze Rule, associated EPA guidance, and NDEP's request, Graymont understands that NDEP will only move forward with requiring emission reductions from the Graymont Pilot Peak kilns if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to DEQ. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

The report identifies the following potential control technologies for the Graymont lime kilns:

Pollutant	Emission Reduction Measure	Technically Feasible?	Cost Effective?	Appropriate for Emissions Reduction?	Notes
SO_2	Inherent Dry Scrubbing	Yes	Yes	Yes	Already inherent to the system
	Alternative Low Sulfur Fuels	No	No	No	Unproven in the lime industry, and natural gas is not currently available to the Pilot Peak plant.
	Wet Scrubbing	No	No	No	Wet scrubbers require substantial water use that exceeds the water rights for the Pilot Peak plant.
	Semi-Wet/Dry Scrubbing	Yes	No	No	Very cost ineffective, and results in a very limited impact on SO_2 emissions in the region.
NO_X	Reduce Peak Flame Zone Temperature	No	N/A	No	
	Low NO_x Burners (LNB)	Yes	Yes	Yes	Already installed and operating.

Pollutant	Emission Reduction Measure	Technically Feasible?	Cost Effective?	Appropriate for Emissions Reduction?	Notes
	Proper Kiln Operation	Yes	Yes	Yes	Proper kiln operation is technically feasible and currently employed at this facility.
	Preheater Kiln Design	Yes	Yes	Yes	The kilns currently feature a preheater.
	Selective Catalytic Reduction (SCR)	No	N/A	No	SCR is largely unproven on lime kilns, as there is no documented instance of this technology in the industry.
	Selective Non-Catalytic Reduction (SNCR)	No	No	No	There is only one RBLC entry for a lime kiln installing SNCR, and the details of its installation remain private. Even if feasible, SNCR is also not cost effective for Pilot Peak.
PM_{10}	Baghouse	Yes	Yes	Yes	Already installed and operating.

It is also worth noting that these three lime kilns were all permitted under EPA's PSD program and were determined to meet BACT at the time those permits were issued and the sources constructed. Furthermore, the NO_X, SO_2, and PM_{10} controls that the Pilot Peak kilns currently utilize are consistent with recent BACT determinations for new rotary preheater lime kilns.[1] Graymont expects that control programs under the current regional haze efforts will not go beyond BACT.

This report outlines Graymont's evaluation of possible options for reducing the emissions of NO_X, SO_2, and PM_{10} at its Pilot Peak facility near West Wendover, Nevada. There are currently no technically feasible and cost effective reduction options available beyond current best practices for the Graymont facility. Therefore, the baseline emissions provided in this analysis are expected to be the same as those of the "control scenario" for the Graymont Pilot Peak facility.

[1] Ibid.

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. In establishing a reasonable progress goal for a Class I area, the state must (40 CFR 51.308(d)(*i*)):

(A) consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

(B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.

With the second planning period under way for regional haze efforts, there are a few key distinctions from the processes that took place during the first planning period. Most notably, the second planning period analysis will distinguish between “natural” and “anthropogenic” sources. Using a Photochemical Grid Model (PGM), the EPA will establish what are, in essence, background concentrations both episodic and routine in nature to compare manmade source contributions against.

On April 12, 2019, NDEP sent a letter to Graymont requesting that they assist in “developing information for the reasonable progress analysis” for Graymont’s Pilot Peak plant.[2] Graymont understands that the information provided in a four-factor review of control options will be used by EPA in their evaluation of reasonable progress goals for Nevada. The purpose of this report is to provide information to NDEP regarding potential SO_2 and NO_X emission reduction options for the Graymont Pilot Peak lime kilns. Based on the Regional Haze Rule, associated EPA guidance, and DEQ’s request, Graymont understands that NDEP will only move forward with requiring emission reductions from the Graymont Pilot Peak lime kilns if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to NDEP. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

[2] Letter from NDEP to Graymont dated April 12, 2019.

The information presented in this report considers the following four factors for the emission reductions:

Factor 1. Costs of compliance
Factor 2. Time necessary for compliance
Factor 3. Energy and non-air quality environmental impacts of compliance
Factor 4. Remaining useful life of the kilns

Factors 1 and 3 of the four factors that are listed above are considered by conducting a step-wise review of emission reduction options in a top-down fashion similar to the top-down approach that is included in the EPA RHR guidelines[3] for conducting a review of Best Available Retrofit Technology (BART) for a unit[4]. These steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Factor 4 is also addressed in the step-wise review of the emission reduction options, primarily in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by limited equipment life. Once the step-wise review of control options was completed, a review of the timing of the emission reductions is provided to satisfy Factor 2 of the four factors.

A review of the four factors for SO_2 and NOx can be found in Sections 5 and 6 of this report, respectively. Section 4 of this report includes information on the Graymont Pilot Peak kilns' existing/baseline emissions.

[3] The BART provisions were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 5, 2005.

[4] References to BART and BART requirements in this Analysis should not be construed as an indication that BART is applicable to the Graymont Pilot Peak facility.

3. SOURCE DESCRIPTION

The Graymont Western US, Inc. Pilot Peak Plant is located in Elko County, Nevada, approximately 10 miles northwest of West Wendover. The nearest Class I area to the plant is the Jarbidge Wilderness Area. It is approximately 130 kilometers northwest of the Pilot Peak plant.

The facility operates three horizontal rotary preheater lime kilns. The three kilns are nearly identical in design and operations, although the production rates for each kiln vary. Kilns 1, 2, and 3 are permitted for producing lime at a rate of 25, 33.3, and 50 tons per hour, respectively.

All three kilns use coal as a primary fuel source. Typical annual fuel usage rates for the three kilns combined are approximately 130,000 tons per year of coal (at approximately 11,600 Btu/lb). Fuels typically used for kiln startup include diesel and propane. Natural gas is not available at the plant.

Further details of the fuel throughputs and emission rates are provided in Section 4.

4. EXISTING EMISSIONS

This section summarizes emission rates that are used as baseline rates in the four factor analyses presented in Sections 5, 6, and 7 of this report.

Baseline annual emissions for NO_X, SO_2, and PM_{10} are calculated based on stack test data combined with annual production and consistent with annual emission inventory reports. For the purposes of this analysis, the average annual emissions from 2013 and 2014 are used as the baseline for evaluation because the annual production rates were highest in 2013 and 2014 compared to other recent years and are expected to be consistent with anticipated production rates in future years. The baseline annual emission rates are summarized in Table 4-1.

Table 4-1. Annual Baseline Emission Rates

Pollutant	Annual Emissions [a] (tons/year)			
	Kiln 1	**Kiln 2**	**Kiln 3**	**Total Kiln Emissions**
NO_X	135.30	173.07	206.88	515.25
SO_2	0.51	0.35	3.52	4.38
PM_{10}	17.43	25.23	8.45	51.11

[a] Baseline emissions are the average of 2013 and 2014 emissions, as submitted in the annual emission inventories. Annual emission inventory rates from the lime kilns are based on stack tests conducted annually on a lb/ton basis and annual production of lime.

The four-factor analysis is satisfied by conducting a step-wise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the step-wise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline SO_2 emission rates that are used in the SO_2 four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report. The kilns currently have inherent process limestone/lime scrubbing as SO_2 controls which are determined to be BACT at the time of their PSD permit issuance dates and which is also commonly determined as BACT for preheater rotary kilns being permitted today.[5]

5.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES

Sulfur dioxide, SO_2, is generated during fuel combustion in a lime kiln, as the sulfur in the fuel is oxidized by oxygen in the combustion air. Sulfur in the limestone raw material can also contribute to a kiln's SO_2 emissions, though the proportion of sulfur contained in the raw material is much less than that of the fuel.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for the Pilot Peak kilns are summarized in Table 5-1. The retrofit controls include both add-on controls that eliminate SO_2 after it is formed and switching to lower sulfur fuels which reduces the formation of SO_2.

Table 5-1. Available SO_2 Control Technologies for Pilot Peak Kilns 1, 2, and 3

SO_2 Control Technologies
Inherent Dry Scrubbing Alternative Low Sulfur Fuels Wet Scrubbing Semi-Wet/Dry Scrubbing

[5] See Mississippi Lime permit (IL) from December 2010.

5.1.1. Inherent Dry Scrubbing

SO_2 is inherently scrubbed within a lime kiln system due to the presence of large volumes of alkaline materials in the system, including limestone in the preheater that all kiln exhaust gases pass through. A typical kiln system scrubs approximately 90% of SO_2 (originating from both fuel sulfur and raw material sulfur) that would otherwise leave the stack. This in-situ scrubbing mechanism is commonly determined as BACT for preheater rotary kilns being permitted today.[6] Dry sorbent injection operates under a similar principle, using the injection of lime particulate into the process stream to initiate the same reaction. Dry sorbent injection is not considered an available control methodology, because the reaction is already taking place inherently as part of the lime kiln process.

5.1.2. Alternative Low Sulfur Fuels

Fuels that can be considered for use in the lime kilns must have sufficient heat content, be dependable and readily available locally in significant quantities so as to not disrupt continuous production. Also, they must not adversely affect product quality.

Currently, the Graymont Pilot Peak kilns use coal as the primary fuel source during normal operations. Alternative lower-sulfur fuels that can be considered include natural gas and diesel.

In the case of natural gas, there is currently no natural gas supplied to the facility. The nearest natural gas pipeline is approximately 45-50 miles north of the plant, and there are no plans to run a pipeline towards the area of the plant. Therefore, natural gas is not considered an available alternative control method at this time.

In the case of diesel, there are no examples of kilns that fire 100% diesel fuel for lime production. Therefore, the use of diesel fuel is not a commercially established emission reduction method and is not considered an available, feasible option at this time. Only the all-coal scenario will be considered going forward.

5.1.3. Wet Scrubbing

A wet scrubber is a tail pipe technology that may be installed downstream of the kilns. In a typical wet scrubber, the flue gas flows upward through a reactor vessel that has an alkaline reagent flowing down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to distribute the reagent across the scrubber vessel. The calcium (or other alkaline reagent) in the reagent reacts with the SO_2 in the flue gas to form calcium sulfite and/or calcium sulfate that is removed with the scrubber sludge and is disposed. Most wet scrubber systems used forced oxidation to assure that only calcium sulfate sludge is produced.

5.1.4. Semi-Wet/Dry Scrubbing

Semi-wet/dry scrubbing uses a scrubber tower installed prior to the baghouse. Atomized hydrated lime slurry is sprayed into the exhaust flue gas. The lime absorbs the SO_2 in the exhaust and turns it into a powdered calcium/sulfur compound. The particulate control device removes the solid reaction products from the gas stream.

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[6] See BACT determinations at Chemical Lime, Ltd. in Comal, TX, Mississippi Lime Company in Randolph, IL, the Clifton Lime Plant in Bosque, TX, and Graymont's facility in Bayfield, WI in the RBLC search in Appendix A.

5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

5.2.1. Inherent Dry Scrubbing

Inherent dry scrubbing occurs in the lime kiln systems and is particularly effective in rotary preheater type kilns. Baseline emissions in Section 4 account for this form of SO_2 control. All alternative methods of SO_2 control in this analysis conservatively assume that the kilns maintain the current level of inherent dry scrubbing.

5.2.2. Alternative Low Sulfur Fuels

There are no alternative, low sulfur fuels that are technically feasible and available for the Pilot Peak kilns at this time.

5.2.3. Wet Scrubbing

A wet scrubbing system utilizes a ground alkaline agent, such as lime or limestone, in slurry to remove SO_2 from stack gas. The spent slurry is dewatered using settling basins and filtration equipment. Recovered water is typically reused to blend new slurry for the wet scrubber. A significant amount of makeup water is required to produce enough slurry to maintain the scrubber's design removal efficiency. Water losses from the system occur from evaporation into the stack gas, evaporation from settling basins, and retained moisture in scrubber sludge.

Graymont estimates that the slurry required for all three kilns will be use approximately 1,300 gallons per minute (gpm) of water.[7] Approximately 50% of this water can be recovered from dewatering efforts. The remaining 650 gpm per kiln will need to be continuously added to the system. For all three kilns, this amounts to 308.9 million gallons per year.

The Pilot Peak plant's water rights entitle the plant to use up to approximately 138 million gallons per year in total under State of Nevada Division of Water Resources permits 42378, 59341, 63441, and 86853, or approximately 262 gpm. The water is primarily used for mining purposes, but even if all 137 million gallons were available to the plant to operate the wet scrubbers, the facility would need to acquire the rights to more than an additional 171 million gallons of water per year to operate three wet scrubbers and provide for possible other demands by the plant for water. All water rights in that area of Nevada have already been appropriated, so the facility does not have the water resources available to operate wet scrubbers at the facility.

Wet scrubbing SO_2 control technology is technically infeasible for this facility because the Pilot Peak plant does not have adequate water resources to operate wet scrubbers. Therefore, this technology is not considered further.

5.2.4. Semi-Wet/Dry Scrubbing

Semi-wet/dry scrubbing uses considerably less water than wet scrubbing; therefore, it is technically feasible and will be considered further.

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[7] Based on Graymont's wet scrubber on 500 ton per day lime kiln at Cricket Mountain, Utah facility.

5.3. STEP 3: RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options to effectiveness. Table 5-2 presents potential SO_2 control technologies for the kilns and their associated control efficiencies.

Table 5-2. Ranking of SO_2 Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Control Efficiency (%)
SO_2	Semi-wet/dry Scrubbing	90.0 [a]
	Inherent Dry Scrubbing	Base case [b]

[a] Assumes 95% control equipment uptime.
[b] Estimated inherent SO_2 control efficiency is 90%. Additional reductions from alternative control methods are applied to the base case, conservatively assuming that reduction from inherent dry scrubbing is unaffected by the reduction options.

5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

5.4.1. Cost of Compliance

For purposes of this four-factor analysis, the capital costs, operating costs, and cost effectiveness of semi-wet/dry scrubbing have been estimated by scaling the capital and operating costs used in the first round of regional haze by the Chemical Engineering Plant Cost Index (CEPCI).

5.4.1.1. Control Costs

The capital and operating costs of the semi-wet/dry scrubber used in the cost effectiveness calculations are estimated based on vendor quotes obtained during the first planning period for similar sources, along with published calculations methods. The lime kilns at Graymont's Pilot Peak facility are similar in configuration and operation to the Graymont kilns for which the vendor quote was developed. Additionally, the control technology is well-established.[8] Therefore, Graymont does not expect any substantive changes in the engineering design and cost calculation of a retrofit for semi-wet/dry scrubbers relative to the vendor quote obtained during the first round of regional haze. The capital cost is annualized over a 20-year period and then added to the annual operating costs to obtain the total annualized cost. The details of the capital and operating cost estimates are provided in Appendix B of this report. The control cost for each option is summarized in Table 5-3.

[8] The most recently published EPA Control Technology Fact Sheet for semi-dry scrubbers was published in 2003, predating the first round of regional haze. https://www3.epa.gov/ttncatc1/cica/files/ffdg.pdf

5.4.1.2. Annual Tons Reduced

The annual tons reduced that are used in the cost effectiveness calculations are determined by subtracting the estimated controlled annual emission rates from the baseline annual emission rates. The baseline annual emission rates are summarized in Table 4-1. For a semi-wet/dry scrubber, the controlled annual emission rate is based on the assumed maximum control efficiency noted in Table 5-2. Details are provided in Appendix B.

An estimate of the amount of SO_2 that may be reduced annually via a semi-wet/dry scrubber is summarized in Table 5-3.

5.4.1.3. Cost Effectiveness

The cost effectiveness is determined by dividing the annual control cost by the annual tons reduced. Table 5-3 summarizes the results.

Table 5-3. Semi-Wet/Dry Scrubber Cost of Compliance Based on Emissions Reduction

Kiln	Control Cost ($/yr)	Baseline Emission Level (tons)	SO_2 Reduction[a] (%)	Emission Reduction (tons)	Cost Effectiveness [b] ($/ton removed)
Kiln 1	$1,887,867	0.51	90.0%	0.44	$4,329,474
Kiln 2	$1,978,379	0.35	90.0%	0.30	$6,681,058
Kiln 3	$2,222,455	3.52	90.0%	3.01	$739,168
Total	$6,088,701	4.37	90.0%	3.74	$1,628,489

[a] Assumes a 95% Uptime for the Add-on Control Device.

[b] Costs for semi-wet/dry scrubbers are cost prohibitive based on anticipated reductions from baseline emissions. If baseline emissions were replaced with worst-case stack test results for SO_2 emissions from 2013-2018 and combined with the higher production rates from 2013 and 2014 (xx total tons per year vs 4.37 tons per year) the costs would remain prohibitive, resulting in cost-effectiveness values of $3,829,618, $288,688, and $464,663 $/ton of lime for Kilns 1, 2, and 3, respectively.

5.4.2. Timing for Compliance

Graymont believes that reasonable progress compliant controls are already in place. However, if NDEP determines that retrofitting the Graymont Pilot Peak kilns to add semi-wet/dry scrubbing is necessary to achieve reasonable progress, it is anticipated that the addition of semi-wet/dry scrubbers can be implemented in approximately 3 years. In order to install semi-wet/dry scrubbers, kiln shutdown will be required. The estimation takes into account this shutdown period and includes an estimate of the time necessary for engineering, permitting, obtaining equipment from vendors, construction, and commissioning.

5.4.3. Energy Impacts

The cost of energy required to operate the control devices has been included in the cost analyses found in Appendix B. To operate any of the add-on control devices, there would be decreased overall plant efficiency due to the operation of these add-on controls. At a minimum, this would require increased electrical usage by the plant with an associated increase in indirect (secondary) emissions from nearby power stations.

5.4.4. Non-Air Quality Impacts

Most of the alternative SO_2 control options that have been considered in this analysis also have additional non-air quality impacts associated with them. A semi-wet/dry hydrated lime control system, for example, will require water to hydrate lime. There will also be additional material collected in the baghouses that will require disposal.

In the Colorado Air Pollution Control Division (APCD) general analysis in the Regional Haze SIP Technical Analyses (April, 2010), the APCD concluded, with regards to SO_2 controls, that wet scrubbing or wet flue gas desulfurization (FGD) has significant negative environmental impacts.[9] In the arid West, including Nevada, water scarcity is a significant concern—this holds especially true when weighing the benefits of a wet vs. a semi-wet or dry control technology, as wet scrubbing requires a significant quantity of water. In addition, environmental concerns associated with sludge disposal and visible plumes resulted in the APCD's determination that wet scrubbers did not qualify as BART.

5.4.5. Remaining Useful Life

The remaining useful life of the kilns does not impact the annualized cost of an add-on control technology (semi-wet/dry scrubbing control) because the useful life is anticipated to be at least as long as the capital cost recovery period, which is 20 years. Similarly, the remaining useful life of the kilns does not impact the annualized cost for the various fuel scenarios that are evaluated.

5.5. SO_2 Conclusion

The lime production process inherently removes the majority of SO_2 that is created from the process. This inherent control measure was BACT for these kilns when they were originally constructed and is still commonly BACT for rotary kilns recently permitted under the PSD program.

In this analysis, no available reduction options for SO_2 emissions are identified that are cost effective and technically feasible for the Pilot Peak facility

[9] Colorado Air Pollution Control Division (APCD), "Colorado Visibility and Regional Haze State Implementation Plan for 12 Mandatory Class I Federal Areas." 7 January, 2011. Page 46. https://environmentalrecords.colorado.gov/HPRMWebDrawer/RecordView/1208384

6. NO_X FOUR FACTOR EVALUATION

The four-factor analysis is satisfied by conducting a step-wise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the step-wise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline NO_X emission rates that are used in the NO_X four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report. The kilns currently utilize low-NO_X burners (LNB), as described in Section 6.1.1.2, below.

6.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

NO_X is produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms “thermal” NO_X and “fuel” NO_X when describing NO_X emissions from the combustion of fuel. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is oxidized in a high temperature zone. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Most of the NO_X formed within a rotary lime kiln is classified as thermal NO_X. Virtually all of the thermal NO_X is formed in the region of the flame at the highest temperatures, approximately 3,000 to 3,600 degrees Fahrenheit. A small portion of NO_X is formed from nitrogen in the fuel that is liberated and reacts with the oxygen in the combustion air.

Step 1 of the top-down control review is to identify available retrofit control options for NO_X. The available NO_X retrofit control technologies for the Pilot Peak kilns are summarized in Table 6-1.

Table 6-1. Available NO_X Control Technologies for Pilot Peak Kilns 1, 2, and 3

NO_x Control Technologies	
Combustion Controls	Reduce Peak Flame Zone Temperature Low NO_x Burners (LNB) Proper Kiln Operation Preheater Kiln Design
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

NO_X emissions controls, as listed in Table 6-1, can be categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature and excess air in the kiln burner, which minimizes NO_X formation. Post-combustion controls such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) convert NO_X in the flue gas to molecular nitrogen and water.

6.1.1. Combustion Controls

6.1.1.1. Reduce Peak Flame Zone Temperature

These are methods of reducing the temperature of combustion products in order to inhibit the formation of thermal NO_X. They include (1) using fuel rich mixtures to limit the amount of oxygen available; (2) using fuel lean mixtures to limit amount of energy input; (3) injecting cooled, oxygen depleted flue gas into the combustion air; and (4) injecting water or steam.

6.1.1.2. Low NO_X Burners

LNBs reduce the amount of NO_X initially formed in the flame. The principle of all LNBs is the same: stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame). LNBs are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. The longer, less intense flames reduce thermal NOx formation by lowering flame temperatures. Control of air turbulence and speed is often controlled via mixing air fans. Some of the burner designs produce a low pressure zone at the burner center by injecting fuel at high velocities along the burner edges. Such a low pressure zone tends to recirculate hot combustion gas which is retrieved through an internal reverse flow zone around the extension of the burner centerline. The recirculated combustion gas is deficient in oxygen, thus producing the effect of flue gas recirculation. Reducing the oxygen content of the primary air creates a fuel-rich combustion zone that then generates a reducing atmosphere for combustion. Due to fuel-rich conditions and lack of available oxygen, formation of thermal NO_X and fuel NO_X are minimized[10].

6.1.1.3. Preheater Kiln Design/ Proper Combustion Practices

The use of staged combustion and preheating alone can lead to effective reduction of NO_X emissions. By allowing for initial combustion in a fuel-rich, oxygen-depleted zone, necessary temperatures can be achieved without concern for the oxidation of nitrogen. This initial combustion is then followed by a secondary combustion zone that burns at a lower temperature, allowing for the addition of additional combustion air without significant formation of NO_X.[11]

6.1.2. Post Combustion Controls

6.1.2.1. Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an exhaust gas treatment process in which ammonia (NH_3) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH_3 and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

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[10] USEPA, Office of Air Quality Planning and Standards. Alternative Control Technologies Document – NOx Emissions from Cement Manufacturing. EPA-453/R-94-004, Page 5-5 to 5-8.

[11] Ibid, Page 58.

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

When operated within the optimum temperature range of 480˚F to 800˚F, the reaction can result in removal efficiencies between 70 and 90 percent.[12] The rate of NO_X removal increases with temperature up to a maximum removal rate at a temperature between 700˚F and 750˚F. As the temperature increases above the optimum temperature, the NO_X removal efficiency begins to decrease. As of this report, there are no known instances of SCRs installed on lime kilns.

6.1.2.2. Selective Non-Catalytic Reduction

In SNCR systems, a reagent is injected into the flue gas within an appropriate temperature window. The NO_X and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NO_X reductions.

Like SCR, SNCR uses ammonia or a solution of urea to reduce NO_X through a similar chemical reaction.

$$2NO + 4NH_3 + 2O_2 \rightarrow 3N_2 + 6H_2O$$

SNCR residence time can vary between 0.001 seconds and 10 seconds.[13] However, increasing the residence time available for mass transfer and chemical reactions at the proper temperature generally increases the NO_X removal. There is a slight gain in performance for residence times greater than 0.5 seconds. The EPA Control Cost Manual indicates that SNCR requires a higher temperature range than SCR of between approximately 1,550˚F and 1,950˚F,[14] due to the lack of a catalyst to lower the activation energies of the reactions; however, the control efficiencies achieved by SNCR vary across that range of temperatures. That said, the effectiveness of SNCR on lime kilns is largely unproven. Lime kilns present unique technical challenges not experienced by cement kilns. While mid-kiln injection is often the most effective method of implementing SNCR on cement kilns, injection at that location is not feasible for a lime kiln. Lime kilns experience lower NO_X concentrations at a given point in the kiln, have shorter residence times, and face issues in the stability of temperature profiles when compared to cement kilns. At higher temperatures, NO_X reduction is less effective.[15] In addition, a greater residence time is required when operating at lower temperatures.

In cement kilns SNCR can be applied as a tailpipe technology or in a certain combustion zone of kilns to facilitate SNCR in a non-tailpipe mode (mid-kiln SNCR). However, there are important differences between and lime kiln and cement kiln that cause technical barriers to mid-kiln firing. The lime industry has a severely limited track record in determining the feasibility or control level that could be attained if mid-kiln

[12] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Page 2-9 and 2-10.

[13] Air Pollution Control Cost Manual, Section 4, Chapter 1, Selective Non-Catalytic Reduction, NOx Controls, EPA/452/B-02-001, Page 1-8

[14]Ibid, Page 1-6

[15] USEPA, Office of Air Quality Planning and Standards. Alternative Control Technologies Document – NO_X Emissions from Cement Manufacturing. EPA-453/R-94-004, Section 5.2.2, Page 5-21.

SNCR were attempted on the Pilot Peak kilns. The aforementioned technical barriers to SNCR implementation have limited the technology's use in the industry, with temperature, residence time, and lower NO_X concentrations distinguishing lime production from the cement production process. The RACT/BACT/LAER Clearinghouse (RBLC) database includes only one instance of a lime kiln that was permitted with SNCR as control for NO_X emissions.[16] The permit documents indicate that after conducting a trial with the SNCR, a lower limit would be established that takes into account the control of NO_X emissions achieved by the SNCR (unless it is demonstrated to not provide effective control or result in unacceptable consequences). Updated permit files have not included a reduced permit limit, and there is no publicly available evidence of the trial results. Based on the record, the SNCR installation and reduction for this RBLC search result has not been demonstrated. Additionally, for the only other instances of known SNCR installations on different lime kilns (which do not appear in RBLC results), very limited information is available on the details of the kilns necessary for Graymont to evaluate whether the application of SNCR in that instance could be implemented at Pilot Peak. Even though SNCR has not been demonstrated as a successful control option for NO_X emissions from lime kilns, indicating the technology may not meet the criteria to be considered available, Graymont conservatively considers SNCR available and will evaluate the technical feasibility further.

6.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NO_X control technologies that were identified in Step 1.

6.2.1. Combustion Controls

6.2.1.1. Reduce Peak Flame Zone Temperature

In a lime kiln, product quality is co-dependent on temperature and atmospheric conditions within the system. Although low temperatures inhibit NO_X formation, they also inhibit the calcination of limestone. For this reason, methods to reduce the peak flame zone temperature in a lime kiln burner are technically infeasible.

6.2.1.2. Low NO_X Burners

The facility currently operates low-NO_X burners in the lime kilns. Coal is delivered to the burners using a direct fired system. However, to limit NO_X, only enough primary air is used to sweep coal out of the mill. This is similar to using an indirect fired system, which also limits primary air to the burners while delivering fuels.

Baseline emissions are based on the operation of these low NO_X burners. All alternative methods of NO_X control in this analysis will assume that the kilns continue to operate these burners.

6.2.1.3. Preheater Kiln Design/Proper Combustion Practices

Proper combustion practices and preheater kiln design are considered technically feasible for Graymont and will be considered further.

[16] RBLC Search results are provided in 7.Appendix A, see the entry for the Mississippi Lime Company.

6.2.2. Post Combustion Controls

6.2.2.1. Selective Catalytic Reduction

Efficient operation of the SCR process requires fairly constant exhaust temperatures (usually ± 200°F).[17] Fluctuation in exhaust gas temperatures reduces removal efficiency. If the temperature is too low, ammonia slip occurs. Ammonia slip is caused by low reaction rates and results in both higher NO_X emissions and appreciable ammonia emissions. If the temperature is too high, oxidation of the NH_3 to NO can occur. Also, at higher removal efficiencies (beyond 80 percent), an excess of NH_3 is necessary, thereby resulting in some ammonia slip. Other emissions possibly affected by SCR include increased PM emissions (as ammonia salts result from the reduction of NO_X and are emitted in a detached plume) and increased SO_3 emissions (from oxidation of SO_2 on the catalyst).

To reduce fouling the catalyst bed with the PM in the exhaust stream, an SCR unit can be located downstream of the particulate matter control device (PMCD). However, due to the low exhaust gas temperature exiting the PMCD (approximately 350°F), a heat exchanger system would be required to reheat the exhaust stream to the desired reaction temperature range of between 480°F to 800°F. The source of heat for the heat exchanger would be the combustion of fuel[18], with combustion products that would enter the process gas stream and generate additional NO_X. Therefore, in addition to storage and handling equipment for the ammonia, the required equipment for the SCR system will include a catalytic reactor, heat exchanger and potentially additional NO_X control equipment for the emissions associated with the heat exchanger fuel combustion.

High dust and semi-dust SCR technologies are still highly experimental. A high dust SCR would be installed prior to the dust collectors, where the kiln exhaust temperature is closer to the optimal operating range for an SCR. It requires a larger volume of catalyst than a tail pipe unit, and a mechanism for periodic cleaning of catalyst. A high dust SCR also uses more energy than a tail pipe system due to catalyst cleaning and pressure losses.

A semi-dust system is similar to a high dust system. However, the SCR is placed downstream of an ESP or cyclone.

The main concern with high dust or semi-dust SCR is the potential for dust buildup on the catalyst, which can be influenced by site specific raw material characteristics present in the facility's quarry, such as trace contaminants that may produce a stickier particulate than is experienced at sites where the technology is being demonstrated. This buildup could reduce the effectiveness of the SCR technology, and make cleaning of the catalyst difficult, resulting in kiln downtime and significant costs.[19]

No lime kiln in the United States is using any of these SCR technologies. For the technical issues noted above, tail pipe, high dust and semi-dust SCR's are considered technically infeasible at this time.

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[17] Ibid, Page 2-11

[18] The fuel would likely be propane or diesel. There is no natural gas at the facility, and coal would require an additional dust collector.

[19] Preamble to NSPS subpart F, 75 FR 54970.

6.2.2.2. Selective Non-Catalytic Reduction

At temperatures above 2,100°F, NO_X generation starts to occur as shown in the reaction below:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O$$

This reaction causes ammonia to oxidize and form NO instead of removing NO. When temperatures exceed 2200°F, NO formation dominates. This would likely be the case if ammonia were directly injected into the kiln tube. At temperatures below the required range, appreciable quantities of un-reacted ammonia will be released to the atmosphere via ammonia slip.

Based on the temperature profile, there are three locations in a rotary preheater lime kiln system where the ammonia /urea injection could theoretically occur: the stone/preheater chamber, the transfer chute, or after the PMCD. A fourth location that will be considered in this analysis is the kiln tube. In order for SNCR to be technically feasible, at least one of these locations must meet the following criteria: placement of injector to ensure adequate mixing of the ammonia or urea with the combustion gases, residence time of the ammonia with the combustion gases, and temperature profile for ammonia injection.

Figure 6-1 provides a schematic of a preheater/kiln system including typical process temperatures in the system.

Figure 6-1. Preheater – Cross Section

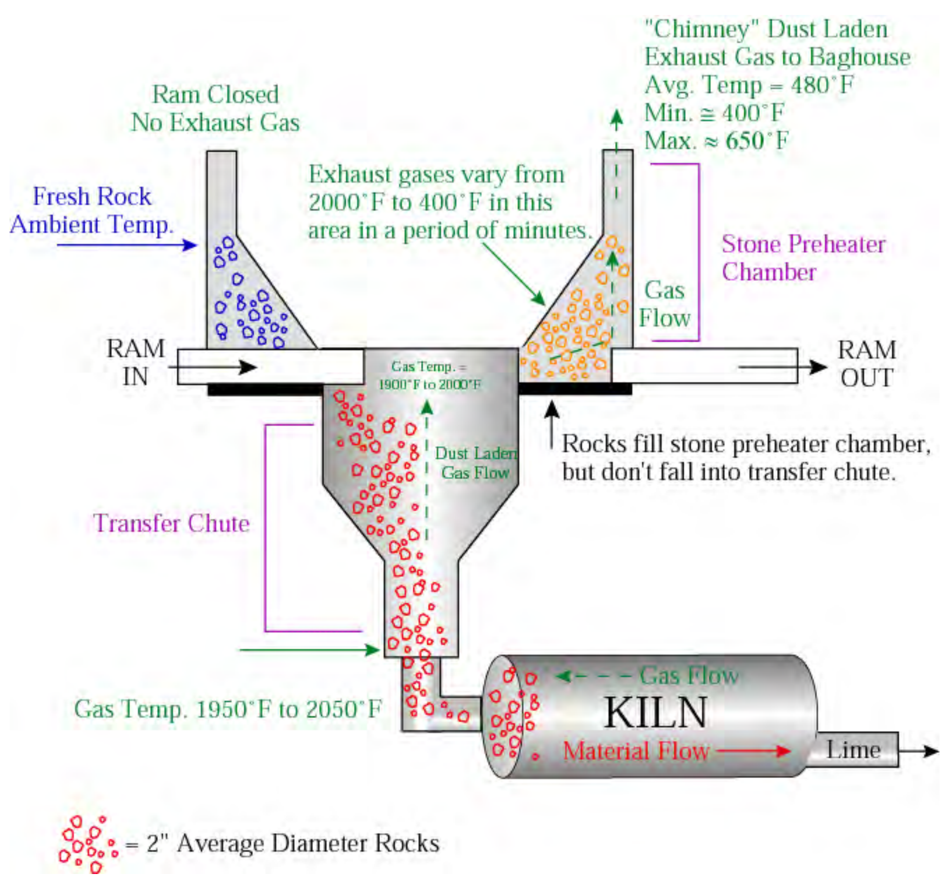

*Figure represents a typical lime kiln preheater, and is not specific to the kilns at the Graymont Pilot Peak facility

SNCR Ammonia/Urea Injection Location - Stone Chamber/Preheater
The required temperature range for the reaction may occur within the preheater. However, the location of the temperature zone varies with time and location as explained below.

In each Graymont Pilot Peak preheater, mechanical rams operate in sequence, transferring limestone, one ram at a time, from the stone chambers into the transfer chute. When a ram is in the "in" position, very little exhaust gas flows through the stone and out the duct. When the ram pulls out, the cold stone drops down and fills the stone heating chamber. The angle of repose of the stone and the configuration of the duct and chamber are such that stone does not continue to fall into the transfer chute. Hot gases, at approximately 1,950˚F, then pass through the stone chamber filled with cold stone. The first gas to pass through the chamber exits the chimney at approximately 400˚F. As the cold stone heats up, the exit gas temperature increases and reaches a high of approximately 600˚F. The ram then strokes and pushes the heated stone into the transfer chute and starts the cycle again. The temperature profile in the stone chamber varies as shown in Figure 6-2.

Figure 6-2. Preheater Stone Chamber Temperature Variation with Time and Location

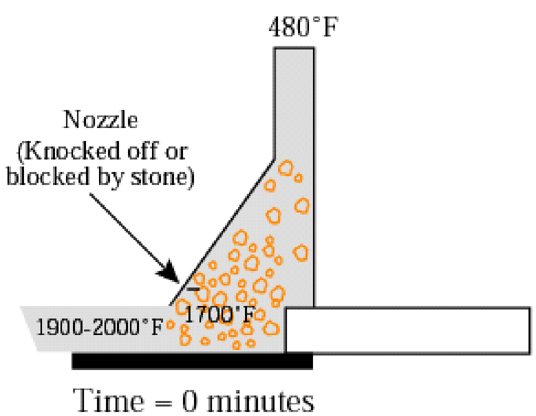

*Figure represents a typical lime kiln preheater, and is not specific to the kilns at the Graymont Pilot Peak facility

Besides the fact that the optimal temperature zone varies in location, the fact that the stone chamber is filled with stone makes using nozzles for injecting the ammonia/urea infeasible. For example, if a nozzle protruded from the wall of the stone chamber, the moving packed bed of rock would either knock it off or wear it off in a very short time. If the nozzle were inset into the wall of the chamber, the moving packed bed of stone would block the spray, and the ammonia or the urea mixture would simply coat a few of the stones, rather than mixing evenly throughout the gas stream. Similarly, if the nozzle were positioned at the roof of the preheater, the ammonia or urea would not be distributed throughout the gas stream. The preheater is approximately 75 percent full of stone, so ammonia or urea sprayed from the top of the preheater would have minimal residence time for distribution through the combustion gases before it would be blocked from distribution by the stone. Regardless of the choice of location for the nozzle, the ammonia or urea would not be effectively distributed through the large surface area of the preheater. These problems make application of SNCR in the stone chamber technically infeasible[20].

SNCR Ammonia/Urea Injection Location – Transfer Chute
As shown in Figure 6-1, the temperature in the transfer chute is approximately 1,950˚F for typical kilns. These temperatures are in the upper bound for the NO_X reduction reaction. Temperatures this high reportedly resulted in approximately 30 percent NO_X reduction in clean (non dust-laden) exhaust streams. Lime kilns do not have clean exhaust streams at this location. Rather, the back end of the transfer chute is an extremely dusty environment, and therefore the exhaust stream is dust-laden. The one SNCR installation in the lime industry has achieved control efficiencies of around 50% with the injection nozzles installed in the bottom of the preheater, at the preheater cone[21]. While this technology is certainly promising, this one example of SNCR installation on a rotary lime kiln does not necessarily transfer to other lime kilns. Effectiveness of SNCR is highly site-dependent, with a variety of factors having the potential to heavily influence the quantities of NO_X controlled. Given the significant range (35-58%) of control efficiencies found for cement kilns, a control efficiency considerably lower than the average for cement of 40% is expected given ideal temperature scenarios (many kilns in the cement industry that utilize SNCR do so in the combustion zone in the calciner, where temperatures are lower than in the kiln). Lime kilns experience significant technical barriers to successful SNCR implementation not shared by the cement industry. When compared to the cement process, lower NO_X concentrations, shorter residence times, and temperatures more frequently outside the optimal range for SNCR application yield lower control efficiencies for lime kilns. Therefore, a control efficiency of no more than 20% is anticipated for the Pilot Peak kilns.

Locating an ammonia or urea injector nozzle in the chute to ensure mixing of the ammonia with the combustion gases would pose similar problems as the problems with the stone chamber location. Stones pour into the chute from the stone chamber, and in order to stabilize a nozzle for injection, the nozzle would need to be positioned out of the direct path of the flow of the stones. Further, the stone pieces that pour into the transfer chute from the chamber take up a large portion of the volume in the chute. Adequate mixing of the ammonia or urea with the combustion gases would be inhibited by the rock. The ammonia or urea would most likely end up on the stones, rather than mixing evenly throughout the gas stream.

The low percent NO_X reduction combined with the uncertainty of the nozzle placement and mixing requirement eliminate the transfer chute as a technically feasible option for Pilot Peak Kilns 1, 2, and 3.

SNCR Ammonia/Urea Injection Location - Inside Rotary Kiln
Ammonia/urea could be injected through a door or port in the kiln shell. Similar to the transfer chute, stone is traveling down the rotary kiln. Consequently, the nozzle would need to be positioned out of the direct path of the flow of the stones. Theoretically, the temperature inside a rotary lime kiln, which is above 2,200 F, would promote the formation of NO from injected ammonia.

Graymont is aware that there have been trials at competing lime facilities with mid-kiln ammonia injection and transfer chute ammonia/urea injection for NO_X reduction. However, the technology costs and technical

[20] Report Concerning BACT for SO_2 and NOx for Proposed Lime Kiln," prepared for Air Pollution Control Division, Clark County Health District, Las Vegas, Nevada, April 1995.

[21] EPA Control Cost Manual, SNCR Cost chapter. 7th Edition, 2016. Page 1-7. https://www3.epa.gov/ttn/ecas/docs/SNCRCostManualchapter7thEdition2016.pdf

details have not become publicly available, so Graymont cannot evaluate if the technology can be successfully applied specifically to the kilns at the Pilot Peak facility.

Since a mid-kiln ammonia injection and transfer chute ammonia/urea injection systems would require extended trials to determine if the technology can effectively control NO_X on the Graymont lime kilns, Graymont must conclude that this type of SNCR is not "available" with respect to the Pilot Peak plant because it is not commercially available. Since it is not commercially available, no vendor performance guarantees can be made to its success. Therefore, this technology cannot be considered technically feasible.

The technology is not commercially available, as defined in 40 CFR Subpart 51, Appendix Y which states that:

> *Two key concepts are important in determining whether a technology could be applied: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.*

Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:

> *The typical stages for bringing a control technology concept to reality as a commercial product are:*
>
> - *Concept stage;*
> - *Research and patenting;*
> - *Bench scale or laboratory testing;*
> - *Pilot scale testing;*
> - *Licensing and commercial demonstration; and*
> - *Commercial sales.*
>
> *A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for purposes of BART review.*
>
> *Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration.*

Though the technology is not considered technically feasible for Graymont's Pilot Peak facility for the reasons outlined above, cost calculations for the implementation of SNCR are included for completeness assuming a 20% control efficiency for NO_X .

6.3. STEP 3: RANK OF TECHNICALLY FEASIBLE NOX CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options to effectiveness. Table 6-2 presents potential NOx control technologies for the kilns and their associated control efficiencies.

Table 6-2. Ranking of NO_X Control Technologies by Effectiveness

Pollutant	Control Technology	Potential Control Efficiency (%)
NO_x	SNCR Low NO_x Burner	20* Base case

* 20% control efficiency is used for cost evaluation based on evaluation of feasibility of SNCR at another Graymont facility.

6.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

6.4.1. Cost of Compliance

In order to assess the cost of compliance for the installation of SNCR, the EPA Control Cost Manual is used. Capital costs for the installation of the SNCR assumed a 20-year life span for depreciation, as well as the current bank prime rate of 4.75% for interest calculations, per NDEP and EPA guidance. The total capital investment includes the capital cost for the SNCR itself, the cost of the air pre-heater required (per the EPA Control Cost Manual, the air pre-heater will require modifications for coal-fired units when SO_2 control is necessary. This value is conservatively assumed for all coal-fired units evaluated for SNCR installation[22]), and the balance of the plant. Annual costs include both direct costs such as maintenance, reagent, electricity, water, fuel, and waste disposal cost and indirect costs for administrative charges and the annuitized capital costs as a capital recovery value. A retrofit factor of 1.5 is used to account for the technical barriers described in section 6.2.2.1, including the existence of only one RBLC reference for an SNCR retrofit on a lime kiln, the difficulty of identifying an injection point that allows for ammonia to enter the gas stream within an optimal temperature window, the low residence times of lime kilns relative to cement kilns, and the relatively low inlet NO_X concentrations that limit the effectiveness of the control technology. The total costs and cost effectiveness of control are summarized in Table 6-3, below.

[22] EPA Control Cost Manual, SNCR Cost chapter. 7th Edition, 2016. Page 1-44. https://www3.epa.gov/ttn/ecas/docs/SNCRCostManualchapter7thEdition2016.pdf

Table 6-3. SNCR Cost Calculation Summary

Kiln	Total Capital Investment	Baseline NO_X Emissions (tpy)	Total Annual Cost	NO_X Emissions Removed (tpy)	Cost Effectiveness ($/ton removed)
1	$5,607,978	135	$539,413	24	$22,048
2	$6,173,878	173	$597,980	31	$19,108
3	$7,396,811	207	$719,345	37	$19,229
Total Project	$19,178,666	515	$1,856,738	93	$19,929

6.4.2. Timing for Compliance

Graymont believes that reasonable progress compliant controls are already in place. However, if NDEP determines that retrofitting the Graymont Pilot Peak kilns to add SNCR is necessary to achieve reasonable progress, it is anticipated that the addition of SNCR can be implemented in approximately 2.5 to 3 years. The estimation includes the time necessary for engineering, permitting, obtaining equipment from vendors, construction, and commissioning.

6.4.3. Energy Impacts and Non-Air Quality Impacts

As previously stated, the cost of energy and water required for successful operation of the SNCR are included in the calculations, which can be found in detail in Appendix C. The installation is expected to decrease the efficiency of the overall facility, particularly as significant energy and water use is needed beyond current plan operation requirements.

6.4.4. Remaining Useful Life

Graymont has assumed this control equipment will last for the entirety of the 20-year amortization period, which is reflected in the cost calculations.

6.5. NO_X CONCLUSION

The facility currently uses low NO_X burners in its three kilns to minimize NO_X emissions. The use of low NO_X burners is a commonly applied technology in current BACT determinations for new rotary preheater lime kilns today. The application of SCR has never been attempted on a lime kiln. SNCR has only one RBLC entry documenting implementation on a lime kiln. The use of these controls does not represent a cost effective control technology given the limited expected improvements to NO_X emission rates, high uncertainty of successful implementation, high capital investment, and high cost per ton NO_X removed.

7.1. PM$_{10}$ EMISSIONS FROM LIME KILNS

PM$_{10}$ emissions from the lime kilns typically represent the largest ducted sources of PM$_{10}$ at a given lime manufacturing plant. PM$_{10}$ emissions generated in the kilns are controlled by baghouses.

The use of a baghouse for control of PM$_{10}$ from lime kilns is consistent with current BACT determinations. RBLC search results are provided in Appendix A, for reference. The average baseline emission factor for Kiln 3 of 0.057 lb/ton of lime is lower than even the lowest emission limit listed in the RBLC database. While the emission factors for kilns 1 and 2 are higher for 2013 and 2014 (at 0.272 and 0.255 lb/ton, respectively), more recent PM$_{10}$ stack test data following replacements of the Kilns 1 and 2 baghouses indicate that emissions from those kilns are also lower than recent limits in the RBLC database.[23] For consistency with NO_X and SO_2 evaluations, the emission rates and factors for 2013 and 2014 are listed. Based on these calculated emission rates, Pilot Peak kilns operate with a comparable or better level of PM$_{10}$ emissions controls than those recently permitted under the PSD BACT program. No additional control technologies for PM$_{10}$ control on lime kilns were identified in the RBLC database; therefore, no additional PM$_{10}$ controls will be evaluated for the purposes of this analysis.

7.2. ADDITIONAL SOURCES OF PM$_{10}$ EMISSIONS

In addition to the PM$_{10}$ emissions from the lime kilns, the Pilot Peak facility also generates PM$_{10}$ emissions from various raw material storage and transfer locations at the plant, including several conveyors for limestone, coal, and lime product. Emissions from conveyors and transfers are controlled using either a baghouse or enclosed transfer. Where baghouses and enclosures are not possible, wet suppression or good operating practices are used for the control of PM$_{10}$ emissions. A table summarizing the additional sources of PM$_{10}$ emissions and the associated emission control methods is provided in Appendix D. These emission controls are consistent with recent BACT determinations.

Additionally, given the nature of fugitive emissions, the PM$_{10}$ emissions generated outside of baghouses/stacks are not expected to travel far from the facility, and are thus anticipated to have a minimal impact on visibility impairment on the nearest Class I area (Jarbidge Wilderness Area at a distance of 130 kilometers).

No additional controls were identified in the RBLC database; therefore, no additional controls from these various additional sources will be evaluated in this analysis.

7.3. PM$_{10}$ CONCLUSION

Graymont concludes that no additional PM$_{10}$ emissions controls are necessary for the Pilot Peak facility for Nevada's reasonable progress for regional haze. Current emissions reduction methods for both the lime kilns and the material handling emissions at the facility were considered BACT when the facility obtained its permit and remain consistent with recent BACT decisions.

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[23] The baghouse Kiln 1 was replaced in 2016 and the baghouse in Kiln 2 was replaced in 2017. 2018 stack test results demonstrate a PM$_{10}$ emission factor for Kilns 1 and 2 of 0.025 and 0.029 lb/ton of lime, respectively.

8. CONCLUSION

This report outlines Graymont's evaluation of possible options for reducing the emissions of NO_X, SO_2, and PM_{10} at its Pilot Peak facility near West Wendover, Nevada. There are currently no technically feasible and cost effective reduction options available for the Graymont facility beyond current best practices. Therefore, the emissions for the 2028 on-the-books/on-the-way modeling baseline are expected to be the same as those used in the "control scenario" for the Graymont Pilot Peak facility.

APPENDIX A : RBLC SEARCH RESULTS

Table A-1. RBLC Search Results

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVERAGE TIME CONDITION	EMISSION LIMIT 2	EMISSION LIMIT 2 UNIT	EMISSION LIMIT 2 AVGERAGE TIME CONDITION
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Two Rotary Kilns	Coal; petroleum coke	50	tons lime/hour, each	Nitrogen Oxides (NOx)	Low excess air to minimize formation of NOx and selective non-catalytic reduction (SNCR) technology.	3.5	LBS/TON LIME PRODUCE	30-DAY ROLLING AVERAGE	2.61	LBS/TON LIME PRODUCE	12-MONTH ROLLING AVERAGE
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 2	natural gas, coal, and petroleum coke	504	tons per day	Nitrogen Oxides (NOx)		5	LB/TON OF LIME PROD		0		
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 3	natural gas, coal, and petroleum coke	850	tons per day	Nitrogen Oxides (NOx)		2.6	LB/TON OF LIME PROD		0		
WI-0250	GRAYMONT (WI) LLC	GRAYMONT (WI) LLC	WI	2/6/2009	P50 (S50). PREHEATER EQUIPPED, ROTARY LIME KILN	COAL	54	T/H STONE	Nitrogen Oxides (NOx)	GOOD COMBUSTION CONTROL, OPTIMIZATION	1.83	LB/T	24 HOUR AVG.	0.7	LB/MMBTU	MONTHLY AVG.
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Two Rotary Kilns	Coal; petroleum coke	50	tons lime/hour, each	Particulate matter, filterable (FPM)	Baghouse	0.14	LB/TON	3-HOUR AVERAGE	0		
WI-0250	GRAYMONT (WI) LLC	GRAYMONT (WI) LLC	WI	2/6/2009	P50 (S50). PREHEATER EQUIPPED, ROTARY LIME KILN	COAL	54	T/H STONE	Particulate matter, fugitive	FABRIC FILTER BAGHOUSE	0.46	LB/T	HIGH ORGANIC CARBON STONE	0.15	LB/T	LOW ORGANIC CARBON STONE
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Two Rotary Kilns	Coal; petroleum coke	50	tons lime/hour, each	Particulate matter, total < 10 Âµ (TPM10)	Baghouse	0.18	LBS/TON	3-HOUR AVERAGE	0		
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 2	natural gas, coal, and petroleum coke	504	tons per day	Particulate matter, total < 10 Âµ (TPM10)	The use of fabric filter to achieve a 0.01 gr/dscf filterable and condensable PM10.	0			0		
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 3	natural gas, coal, and petroleum coke	850	tons per day	Particulate matter, total < 10 Âµ (TPM10)	The use of fabric filter to achieve a 0.01 gr/dscf filterable and condensable PM10.	0			0		
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Two Rotary Kilns	Coal; petroleum coke	50	tons lime/hour, each	Particulate matter, total < 2.5 Âµ (TPM2.5)	Baghouse	0.105	LBS/TON	3-HOUR AVERAGE	0		
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Two Rotary Kilns	Coal; petroleum coke	50	tons lime/hour, each	Sulfur Dioxide (SO2)	Natural absorptive capacity of lime kiln dust.	0.5	LBS/TON LIME	30-DAY ROLLING AVERAGE	0		
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 2	natural gas, coal, and petroleum coke	504	tons per day	Sulfur Dioxide (SO2)	Limiting the fuel sulfur input, in addition to the dry scrubbing inherent in these systems.	0			0		
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 3	natural gas, coal, and petroleum coke	850	tons per day	Sulfur Dioxide (SO2)	Limiting the fuel sulfur input, in addition to the dry scrubbing inherent in these systems.	0			0		
TX-0820	CLIFTON LIME PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	4/28/2017	lime kiln	coal	219000	t/yr	Sulfur Dioxide (SO2)	fuel sulfur limits	12.8	LB/TON LIME		0		
WI-0250	GRAYMONT (WI) LLC	GRAYMONT (WI) LLC	WI	2/6/2009	P50 (S50). PREHEATER EQUIPPED, ROTARY LIME KILN	COAL	54	T/H STONE	Sulfur Dioxide (SO2)	FUEL SULFUR LIMIT, INHERENT PROCESS COLLECTION OF SULFUR OXIDES.	0.62	LB/T	24 HOUR AVERAGE	2	PERCENT S	FUEL SULFUR LIMIT

Table A-2. RBLC Search Results - Miscellaneous Sources

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVERAGE TIME CONDITION	EMISSION LIMIT 2	EMISSION LIMIT 2 UNIT	EMISSION LIMIT 2 AVGERAGE TIME CONDITION
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	KY	4/9/2010	COAL STOCKPILE		3000	T/H	Particulate Matter (PM)	WET SUPPRESSION, DUST SUPPRESSENT LOWERING WELL AND COMPACTION.	10	OPACITY	3 MINUTE	0		
WI-0252	SPECIALTY MINERALS INC. - SUPERIOR	SPECIALTY MINERALS INC. (SMI)	WI	7/22/2011	P10 - LIME SILO		0		Particulate Matter (PM)	PNEUMATIC CONVEYING, TOTAL ENCLOSURE AND BIN VENT FABRIC FILTER.	0.13	LB/H		0.005	GR/DSCF	
WI-0252	SPECIALTY MINERALS INC. - SUPERIOR	SPECIALTY MINERALS INC. (SMI)	WI	7/22/2011	F01 - FUGITIVE DUST EMISSIONS		0		Particulate Matter (PM)	PAVING ROADWAYS AND PARKING, MAINTENANCE OF PAVED AREAS AND TOTAL ENCLOSURES FOR RAW MATERIAL TRANSFERS.	0			0		
AL-0313	MONTEVALLO PLANT	LHOIST NORTH AMERICA OF ALABAMA, LLC	AL	5/4/2016	PRODUCT HANDLING SYSTEM	N/A	55000	LB/H OF LIME	Particulate matter, filterable < 10 Âµ (FPM10)	FABRIC FILTER BAGHOUSE	0.002	GR/DSCF		0		
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	LIMESTONE AND DOLOMITE GRINDING MILL BIN AREA	495.00 T/H	0		Particulate matter, filterable < 10 Âµ (FPM10)	BAGHOUSE	0.002	GR/DSCF		0.26	LB/H	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	MIXING AREA MATERIAL HANDLING SYSTEM	780.00 T/H	0		Particulate matter, filterable < 10 Âµ (FPM10)	BAGHOUSE	0.002	GR/DSCF		0.77	LB/H	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	MACHINE DISCHARGE SYSTEM	1155 T/H	0		Particulate matter, filterable < 10 Âµ (FPM10)	BAGHOUSE	0.002	GR/DSCF		1.01	LB/H	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	RECYCLED DUST STORAGE AREA	25.0 T/H	0		Particulate matter, filterable < 10 Âµ (FPM10)		0			0		
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	LIMESTONE UNLOADING & STORAGE AREA		495	T/H	Particulate matter, filterable < 10 Âµ (FPM10)		0.07	LB/H		0.15	T/YR	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	LIMESTONE/DOLOMITE HOPPER, BELT FEEDER & GRIZZLY FEEDER/SCREENER		495	T/H	Particulate matter, filterable < 10 Âµ (FPM10)		0.22	LB/H		0.47	T/YR	
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	KY	4/9/2010	ASH HANDLING		0		Particulate matter, filterable < 10 Âµ (FPM10)	FABRIC FILTER	0.005	GR/DSCF		0		
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	KY	4/9/2010	COAL CRUSHING AND SILO STORAGE		0		Particulate matter, filterable < 10 Âµ (FPM10)	FABRIC FILTER	0.005	GR/DSCF		0		
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	KY	4/9/2010	LIME SILO STORAGES		0		Particulate matter, filterable < 10 Âµ (FPM10)	FABRIC FILTERS	0.005	GR/DSCF		0		
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	KY	4/9/2010	COALING TOWERS		0		Particulate matter, filterable < 10 Âµ (FPM10)	0.0005% DRIFT ELIMINATORS	0			0		
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	KY	4/9/2010	LIMESTONE STORAGE SILOS		40	T/H	Particulate matter, filterable < 10 Âµ (FPM10)	FABRIC FILTER	0.005	GR/DSCF	24 HR	0.51	LB/H (EACH)	24 HR
*TX-0869	LIME MANUFACTURING PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	11/6/2019	Material Handling (Conveyors and Feeders)		0		Particulate matter, filterable < 10 Âµ (FPM10)	BAGHOUSE	0.005	GR/DSCF		0		
*TX-0869	LIME MANUFACTURING PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	11/6/2019	Product Loadout		240900	TON/YR	Particulate matter, filterable < 10 Âµ (FPM10)	BAGHOUSE	0.005	GR/DSCF		0		
AL-0313	MONTEVALLO PLANT	LHOIST NORTH AMERICA OF ALABAMA, LLC	AL	5/4/2016	PRODUCT HANDLING SYSTEM	N/A	55000	LB/H OF LIME	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	FABRIC FILTER BAGHOUSE	0.002	GR/DSCF		0		
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	LIMESTONE AND DOLOMITE GRINDING MILL BIN AREA	495.00 T/H	0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	BAGHOUSE	0.002	GR/DSCF		0.26	LB/H	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	MIXING AREA MATERIAL HANDLING SYSTEM	780.00 T/H	0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	BAGHOUSE	0.002	GR/DSCF		0.77	LB/H	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	MACHINE DISCHARGE SYSTEM	1155 T/H	0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	BAGHOUSE	0.002	GR/DSCF		1.01	LB/H	

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVERAGE TIME CONDITION	EMISSION LIMIT 2	EMISSION LIMIT 2 UNIT	EMISSION LIMIT 2 AVGERAGE TIME CONDITION
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	RECYCLED DUST STORAGE AREA	25.0 T/H	0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	BAGHOUSE	0.002	GR/DSCF		0.16	LB/H	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	LIMESTONE UNLOADING & STORAGE AREA		495	T/H	Particulate matter, filterable < 2.5 Âµ (FPM2.5)		0.01	LB/H		0.015	T/YR	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	LIMESTONE/DOLOMITE HOPPER, BELT FEEDER & GRIZZLY FEEDER/SCREENER		495	T/H	Particulate matter, filterable < 2.5 Âµ (FPM2.5)		0.02	LB/H		0.05	T/YR	
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	KY	4/9/2010	ASH HANDLING		0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	FABRIC FILTER	0.005	G/DSCF	24 BLOCK	0		
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	KY	4/9/2010	COALING TOWERS		0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	BACT FOR PM/PM10/PM2.5 IS 0.0005% DRIFT ELIMINATORS	0			0		
*TX-0869	LIME MANUFACTURING PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	11/6/2019	Material Handling (Conveyors and Feeders)		0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	BAGHOUSE	0.005	GR/DSCF		0		
*TX-0869	LIME MANUFACTURING PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	11/6/2019	Product Loadout		240900	TON/YR	Particulate matter, filterable < 2.5 Âµ (FPM2.5)	BAGHOUSE	0.005	GR/DSCF		0		
WI-0252	SPECIALTY MINERALS INC. - SUPERIOR	SPECIALTY MINERALS INC. (SMI)	WI	7/22/2011	P10 - LIME SILO		0		Particulate matter, filterable < 2.5 Âµ (FPM2.5)	PNEUMATIC CONVEYING, TOTAL ENCLOSURE, BIN VENT FABRIC FILTER	0.026	LB/H		0.001	GR/ACF	
AL-0313	MONTEVALLO PLANT	LHOIST NORTH AMERICA OF ALABAMA, LLC	AL	5/4/2016	LIMESTONE FEED SYSTEM	N/A	110000	LB/H	Particulate matter, filterable (FPM)	WET LIMESTONE	7	% OPACITY	6 MIN AVG	0.014	GR/DSCF	
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Lime Barge Loadout		0		Particulate matter, filterable (FPM)	Telescoping loading spout with suction or aspiration at discharge end and a filter system.	0.004	GR/SCF		0		
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Truck and Rail Loadout		0		Particulate matter, filterable (FPM)	Partial enclosure; fabric filters to treat displaced air during loadout; and loadout practices to minimize spillage.	0.004	GR/SCF		0		
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Limestone Handling Operations (Stack Emissions)		0		Particulate matter, filterable (FPM)		0.014	GR/DSCF		0		
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Limestone Handling Operations (Fugitive Emissions)		0		Particulate matter, filterable (FPM)		0			0		
IN-0139	DUKE ENERGY INDIANA, INC. - EDWARDSPORT GENERAT**	DUKE ENERGY INDIANA, INC. - EDWARDSPORT GENERAT*	IN	3/1/2010	COAL HANDLING AND TRANSFERRING		12000	T/H OF COAL	Particulate matter, filterable (FPM)	BAGHOUSE/BIN VENT COLLECTOR INSERTABLE DUST COLLECTOR	0.003	GR/DSCF	3 HRS	0		
IN-0139	DUKE ENERGY INDIANA, INC. - EDWARDSPORT GENERAT**	DUKE ENERGY INDIANA, INC. - EDWARDSPORT GENERAT*	IN	3/1/2010	LIME AND SODA ASH HANDLING (4 SILOS)		46	T/H EACH	Particulate matter, filterable (FPM)	BIN VENTDUST COLLECTOR	0.019	LB/H *	3 HOURS	0.003	GR/DSCF	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	LIMESTONE UNLOADING (TRUCK)		495	T/H	Particulate matter, filterable (FPM)	DEVELOPMENT, MAINTENANCE, AND IMPLEMENTATAION OF A SITE-SPECIFIC FUGITIVE DUST CONTROL PLAN	0.0011	LB/H	3 HOURS	0.0022	T/YR	
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	LIMESTONE CONVEYOR & ENCLOSED STORAGE (PILE)		495	T/H	Particulate matter, filterable (FPM)	DEVELOPMENT, MAINTENANCE, AND IMPLEMENTATION OF A SITE-SPECIFIC FUGITIVE DUST CONTROL PLAN AND ENCLOSURE	0.05	LB/H	3 HOURS	0.1	T/YR	
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	FURNACE DISCHARGE SYSTEM		1155	T/H	Particulate matter, filterable (FPM)	BAGHOUSE CE017	0.002	GR/DSCF	3 HOURS	0.73	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	WBE LIME STORAGE AREA		7	T/H	Particulate matter, filterable (FPM)	BIN VENT CE020	0.002	GR/DSCF	3 HOURS	0.02	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	WBE RESIDUAL PRODUCT LOADING AREA		7	T/H	Particulate matter, filterable (FPM)	BIN VENT CE020	0.002	GR/DSCF	3 HOURS	0.02	LB/H	3 HOURS

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVERAGE TIME CONDITION	EMISSION LIMIT 2	EMISSION LIMIT 2 UNIT	EMISSION LIMIT 2 AVGERAGE TIME CONDITION
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	RECYCLED DUST STORAGE AREA		7	T/H	Particulate matter, filterable (FPM)	BAGHOUSE CE024	0.002	GR/DSCF	3 HOURS	0.16	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	LIMESTONE/DOLOMITE HOPPER, BELT FEEDER, GRIZZLY FEEDER/SCREENER		495	T/H	Particulate matter, filterable (FPM)	THROUGH THE DEVELOPMENT, MAINTENANCE, AND IMPLEMENTATION OF A SITE-SPECIFIC FUGITIVE DUST CONTROL PLAN	0.9	LB/H	3 HOURS	1.92	T/YR	
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	LIMESTONE/DOLOMITE GRINDING MILL BIN AREA		495	T/H	Particulate matter, filterable (FPM)	BAGHOUSE CE023	0.002	GR/DSCF	3 HOURS	0.22	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	MIXING AREA MATERIAL HANDLING SYSTEM		780	T/H	Particulate matter, filterable (FPM)	BAGHOUSE CE011	0.002	GR/DSCF	3 HOURS	0.34	LB/H	3 HOURS
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	LIMESTONE AND DOLOMITE GRINDING MILL BIN AREA	495.00 T/H	0		Particulate matter, filterable (FPM)	BAGHOUSE	0.002	GR/DSCF		0.26	LB/H	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	MIXING AREA MATERIAL HANDLING SYSTEM	780.00 T/H	0		Particulate matter, filterable (FPM)	BAGNOUSE	0.002	GR/DSCF		0.77	LB/H	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	MACHINE DISCHARGE SYSTEM	1155 T/H	0		Particulate matter, filterable (FPM)	BAGHOUSE	0.002	GR/DSCF		1.01	LB/H	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	DUST RECYCLE SURGE HOPPER & BLOW TANK AREA	28.0 T/H	0		Particulate matter, filterable (FPM)	BAGHOUSE	0.002	GR/DSCF		0.05	LB/H	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	LIMESTONE UNLOADING & STORAGE AREA		495	T/H	Particulate matter, filterable (FPM)		0.2	LB/H		0.41	T/YR	
IN-0185	MAG PELLET LLC	MAG PELLET LLC	IN	4/24/2014	LIMESTONE/DOLOMITE HOPPER, BELT FEEDER & GRIZZLY FEEDER/SCREENER		495	T/H	Particulate matter, filterable (FPM)		0.9	LB/H		1.92	T/YR	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	5/24/2010	DOC-102 - Dock 2 Loading/Unloading Gantry Crane		0		Particulate matter, filterable (FPM)	BACT is selected to be enclosed conveyors as the most stringent control option for material handling conveyors. Water sprays and partial enclosures are additional control methods which will be employed at specific transfer and drop points. BACT for the various loading and unloading operations and similar sources is selected as collection and control by fabric filters.	0.44	LB/H		1.93	T/YR	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	5/24/2010	DST-101-Blast Furnace 1 Topgas Dust Catcher		0		Particulate matter, filterable (FPM)	BACT is selected to be enclosed conveyors as the most stringent control option for material handling conveyors. Water sprays and partial enclosures are additional control methods which will be employed at specific transfer and drop points.	0.01	LB/H		0.04	T/YR	
LA-0239	NUCOR STEEL LOUISIANA	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC	LA	5/24/2010	PIL-101 - Coal Storage Piles		5512	T/h	Particulate matter, filterable (FPM)	BACT is selected to be implementation of wet suppression of dust generating sources by water sprays at each storage pile site	1.48	LB/H		3.99	T/YR	
*TX-0869	LIME MANUFACTURING PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	11/6/2019	Material Handling (Conveyors and Feeders)		0		Particulate matter, filterable (FPM)	BAGHOUSE	0.005	GR/DSCF		0		
*TX-0869	LIME MANUFACTURING PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	11/6/2019	Product Loadout		240900	TON/YR	Particulate matter, filterable (FPM)	BAGHOUSE	0.005	GR/DSCF		0		
AL-0313	MONTEVALLO PLANT	LHOIST NORTH AMERICA OF ALABAMA, LLC	AL	5/4/2016	LIMESTONE FEED SYSTEM	N/A	110000	LB/H	Particulate matter, fugitive	WET LIMESTONE	7	% OPACITY	6 MIN AVG	0		
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	KY	4/9/2010	LIMESTONE UNLOADING		44	T/H	Particulate matter, fugitive	WET SUPPRESSION OR DUST SUPPRESSANT	0			0		
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	KY	4/9/2010	HAUL ROADS		0		Particulate matter, fugitive	PAVED ROADWAYS, CLEANING OR PROMPT REMOVAL OF MATERIAL, AND THE APPLICATION OF WET SUPPRESSION, AS APPLICABLE	0			0		

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVERAGE TIME CONDITION	EMISSION LIMIT 2	EMISSION LIMIT 2 UNIT	EMISSION LIMIT 2 AVGERAGE TIME CONDITION
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	6/30/2017	Fugitive Dust from Unpaved Roads		5024900	VMT/yr	Particulate matter, total < 10 Âµ (TPM10)	Water and Chemical Suppressant Spray	3500	TPY	YEARLY	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	6/30/2017	Material Loading and Unloading		155123914	tpy	Particulate matter, total < 10 Âµ (TPM10)	Best Practical Methods and Fugitive Dust Control Plan (to include water spray)	530	TPY (COMBINED)	YEARLY	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	6/30/2017	Drilling and Blasting		620	blasts/yr	Particulate matter, total < 10 Âµ (TPM10)	Best Practical Methods	273	TPY (COMBINED)	YEARLY	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	6/30/2017	Fugitive Dust from Wind Erosion		0		Particulate matter, total < 10 Âµ (TPM10)	Best Practical Methods / Fugitive Dust Control Plan (includes water suppression)	32	TPY	YEARLY	0		
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	LIMESTONE UNLOADING (TRUCK)		495	T/H	Particulate matter, total < 10 Âµ (TPM10)	DEVELOPMENT, IMPLEMENTATION, AND MAINTENANCE OF SIRE-SPECIFIC FUGITIVE DUST CONTROL PLAN	0.0011	LB/H	3 HOURS	0.0022	T/YR	
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	LIMESTONE CONVEYOR & ENCLOSED STORAGE (PILE)		495	T/H	Particulate matter, total < 10 Âµ (TPM10)	DEVELOPMENT, MAINTENANCE, AND IMPLEMENTATION OF A SITE-SPECIFIC FUGITIVE DUST CONTROL PLAN AND ENCLOSURE	0.02	LB/H	3 HOURS	0.04	T/YR	
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	FURNACE DISCHARGE SYSTEM		1155	T/H	Particulate matter, total < 10 Âµ (TPM10)	BAGHOUSE CE017	0.002	GR/DSCF	3 HOURS	0.73	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	WBE LIME STORAGE AREA		7	T/H	Particulate matter, total < 10 Âµ (TPM10)	BIN VENT CE020	0.002	GR/DSCF	3 HOURS	0.02	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	WBE RESIDUAL PRODUCT LOADING AREA		7	T/H	Particulate matter, total < 10 Âµ (TPM10)	BIN VENT CE020	0.002	GR/DSCF	3 HOURS	0.02	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	RECYCLED DUST STORAGE AREA		7	T/H	Particulate matter, total < 10 Âµ (TPM10)	BAGHOUSE CE024	0.002	GR/DSCF	3 HOURS	0.16	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	LIMESTONE/DOLOMITE HOPPER, BELT FEEDER, GRIZZLY FEEDER/SCREENER		495	T/H	Particulate matter, total < 10 Âµ (TPM10)	DEVELOPMENT, IMPLEMENTATION, AND MAINTENANCE OF A SITE-SPECIFIC FUGITIVE DUST CONTROL PLAN	0.33	LB/H	3 HOURS	0.7	T/YR	
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	LIMESTONE/DOLOMITE GRINDING MILL BIN AREA		495	T/H	Particulate matter, total < 10 Âµ (TPM10)	BAGHOUSE CE023	0.002	GR/DSCF	3 HOURS	0.22	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	MIXING AREA MATERIAL HANDLING SYSTEM		780	T/H	Particulate matter, total < 10 Âµ (TPM10)	BAGHOUSE CE011	0.002	GR/DSCF	3 HOURS	0.34	LB/H	3 HOURS
*TX-0869	LIME MANUFACTURING PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	11/6/2019	Lime Belt Crusher		0		Particulate matter, total < 10 Âµ (TPM10)	BAGHOUSE	0.009	GR/DSCF		0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	6/30/2017	Fugitive Dust from Unpaved Roads		5024900	VMT/yr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Water and Chemical Suppressant Spray	3500	TPY	YEARLY	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	6/30/2017	Material Loading and Unloading		155123914	tpy	Particulate matter, total < 2.5 Âµ (TPM2.5)	Best Practical Methods/Fugitive Dust Control Plan (includes water spray)	530	TPY (COMBINED)	YEARLY	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	6/30/2017	Drilling and Blasting		620	blasts/yr	Particulate matter, total < 2.5 Âµ (TPM2.5)	Best Practical Methods	273	TPY (COMBINED)	YEARLY	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	6/30/2017	Fugitive Dust from Wind Erosion		0		Particulate matter, total < 2.5 Âµ (TPM2.5)	Best Practical Methods / Fugitive Dust Control Plan (includes water suppression)	32	TPY	YEARLY	0		
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	LIMESTONE UNLOADING (TRUCK)		495	T/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	DEVELOPMENT, MAINTENANCE, AND IMPLEMENTATION OF A SITE-SPECIFIC FUGITIVE DUST CONTROL PLAN	0.0011	LB/H	3 HOURS	0.0022	T/YR	
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	LIMESTONE CONVEYOR & ENCLOSED STORAGE (PILE)		495	T/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	DEVELOPMENT, MAINTENANCE, AND IMPLEMENTATION OF A SITE-SPECIFIC FUGITIVE DUST CONTROL PLAN AND ENCLOSURE	0.02	LB/H	3 HOURS	0.04	T/YR	
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	FURNACE DISCHARGE SYSTEM		1155	T/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	BAGHOUSE CE017	0.002	GR/DSCF	3 HOURS	0.73	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	WBE LIME STORAGE AREA		7	T/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	BIN VENT CE020	0.002	GR/DSCF	3 HOURS	0.02	LB/H	3 HOURS

RBLC ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVERAGE TIME CONDITION	EMISSION LIMIT 2	EMISSION LIMIT 2 UNIT	EMISSION LIMIT 2 AVGERAGE TIME CONDITION
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	WBE RESIDUAL PRODUCT LOADING AREA		7	T/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	BIN VENT CE020	0.002	GR/DSCF	3 HOURS	0.02	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	RECYCLED DUST STORAGE AREA		7	T/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	BAGHOUSE CE024	0.002	GR/DSCF	3 HOURS	0.16	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	LIMESTONE/DOLOMITE HOPPER, BELT FEEDER, GRIZZLY FEEDER/SCREENER		495	T/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	DEVELOPMENT, IMPLEMENTATION, AND MAINTENANCE OF A SITE-SPECIFIC FUGITIVE DUST CONTROL PLAN	0.33	LB/H	3 HOURS	0.7	T/YR	
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	LIMESTONE/DOLOMITE GRINDING MILL BIN AREA		495	T/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	BAGHOUSE CE023	0.002	GR/DSCF	3 HOURS	0.22	LB/H	3 HOURS
IN-0167	MAGNETATION LLC	MAGNETATION LLC	IN	4/16/2013	MIXING AREA MATERIAL HANDLING SYSTEM		780	T/H	Particulate matter, total < 2.5 Âµ (TPM2.5)	BAGHOUSE CE011	0.002	GR/DSCF	3 HOURS	0.34	LB/H	3 HOURS
*TX-0869	LIME MANUFACTURING PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	11/6/2019	Lime Belt Crusher		0		Particulate matter, total < 2.5 Âµ (TPM2.5)	BAGHOUSE	0.009	GR/DSCF		0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	6/30/2017	Fugitive Dust from Unpaved Roads		5024900	VMT/yr	Particulate matter, total (TPM)	Water and Chemical Suppressant Spray	3500	TPY	YEARLY	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	6/30/2017	Material Loading and Unloading		155123914	tpy	Particulate matter, total (TPM)	Best Practical Methods/Fugitive Dust Control Plan (includes water spray)	530	TPY (COMBINED)	YEARLY	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	6/30/2017	Drilling and Blasting		620	blasts/yr	Particulate matter, total (TPM)	Best Practical Methods	273	TPY (COMBINED)	YEARLY	0		
AK-0084	DONLIN GOLD PROJECT	DONLIN GOLD LLC.	AK	6/30/2017	Fugitive Dust from Wind Erosion		0		Particulate matter, total (TPM)	Best Practical Methods / Fugitive Dust Control Plan (includes applying water)	32	TPY	YEARLY	0		
*TX-0869	LIME MANUFACTURING PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	11/6/2019	Lime Belt Crusher		0		Particulate matter, total (TPM)	BAGHOUSE	0.009	GR/DSCF		0		

APPENDIX B : SO_2 CONTROL COST CALCULATIONS

Table B-1. Summary of Semi-Dry Scrubber Costs

Kiln	Annual Cost	Tons SO_2 In	Tons SO_2 Reduced	Cost Effectiveness ($/ton reduced)
1	$1,887,867	0.51	0.44	$4,329,474
2	$1,978,379	0.35	0.30	$6,681,058
3	$2,222,455	3.52	3.01	$739,168
Total	$6,088,701	4.37	3.74	$1,628,489

Table B-2. Semi-Dry Scrubber Cost Calculations for Kiln 1

		Notes
Direct Costs		
Purchased Equipment Costs		($5,775,000 from Turbosonic system Quote 2010 for 69,000 acfm @ 300 °F, scaled according to 0.6 power rule)
Scrubber Unit	$5,310,474	
Instrumentation (10% of EC)	incl	
Sales Tax (3% of EC)	incl	
Freight (5% of EC)	incl	
Subtotal, Purchased Equipment Cost (PEC)	$5,310,474	B
Direct Installation Costs		
Foundation (6% of PEC)	Incl	
Supports (6% of PEC)	Incl	
Handling and Erection (40% of PEC)	Incl	
Electrical (1% of PEC)	Incl	
Piping (30% of PEC)	Incl	
Insulation for Ductwork (1% of PEC)	Incl	
Painting (1% of PEC)	Incl	
Turnkey Installation	$1,931,081	
Site Preparation	N/A	No data
Buildings	N/A	No data
Total Direct Cost	**$7,241,555**	
Indirect Costs		
Engineering (10% of PEC)	$531,047	CONTROL COST MANUAL - EPA/452/B-02-001 (CCM), Section 5.1, Chapter 1, Table 1.3
Construction and Field Expense (10% of PEC)	$531,047	CCM, Section 5.1, Chapter 1, Table 1.3
Contractor Fees (10% of PEC)	$531,047	CCM, Section 5.1, Chapter 1, Table 1.3
Start-up (1% of PEC)	$53,105	CCM, Section 5.1, Chapter 1, Table 1.3
Performance Test (1% of PEC)	$53,105	CCM, Section 5.1, Chapter 1, Table 1.3
Contingencies (3% of PEC)	$159,314	CCM, Section 5.1, Chapter 1, Table 1.3
Total Indirect Cost	**$1,858,666**	
Total Capital Investment (TCI) (2010 $)	**$9,100,221**	
Direct Annual Costs		
Hours per Year (330 days per year, 24 hours per day)	8,040	
Operating Labor		
Man-hrs	3,840	Based on Turbosonic system
Rate	$50	Based on Turbosonic system
Subtotal, Operating Labor	$192,000	
Maintenance		
Maintenance	$200,000	Based on Turbosonic system
Subtotal, Maintenance	$200,000	
Utilities		
Electricity		
Demand (kW)	40.84	Based on Turbosonic system - 377,600 kw-hr
Cost ($/kW-hr)	$0.0535	Based on Turbosonic system - assumed $0.07/kW-hr
Subtotal, Electricity	$17,556	
Hydrated Lime		
Amount Required (ton/yr)	3	Based on Turbosonic system (scaled from modeled max SO2 content of 760 lb/hr to 1.49 lb/hr)
Cost ($/ton)	$110.00	Based on Turbosonic system (profit lost to Graymont)
Subtotal, Lime	$341	
Process Water		
Amount Required (gal/yr)	43	Based on Turbosonic system (to hydrate lime). (Scaled from modeled max SO2 content of 760 lb/hr to 1.49 lb/hr).
Cost ($/ton)	$0.24	Based on Turbosonic system
Subtotal, Lime	$11	
Subtotal, Utilities	$17,907	
Total Direct Annual Costs (2010 $)	**$409,907**	
Indirect Annual Costs		
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)	$235,411	
Administrative (2% TCI)	$182,004	0.02 TCI, CCM, Sec 5.1, Ch 1, Table 1.4
Property Tax (1% TCI)	$91,002	0.01 TCI, CCM, Sec 5.1, Ch 1, Table 1.4
Insurance (1% TCI)	$91,002	0.01 TCI, CCM, Sec 5.1, Ch 1, Table 1.4
Capital Recovery (20 year life, 4.75 percent interest)	$714,827	CCM, Sec 1, Ch 2, Eqn 2.8a
Total Indirect Annual Cost (2010 $)	**$1,314,246**	
Total Annualized Cost (2018 $)	**$1,887,867**	2011 Estimate scaled by CEPCI, from 2010 $ (year of the quote) to 2018 $ (most recently published year for index).
Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)	**0.51**	
Pollutant Removed (tons SO_2/yr) 90% removal per vendor	**0.4**	Assumes 95% control equipment uptime
Cost Per Ton of Pollutant Removed	**$4,329,473**	

Table B-3. Semi-Dry Scrubber Cost Calculations for Kiln 2

		Notes
Direct Costs		
Purchased Equipment Costs		
Scrubber Unit	$5,825,073	($5,775,000 from Turbosonic system Quote 2010 for 69,000 acfm @ 300 °F, scaled according to 0.6 power rule)
Instrumentation (10% of EC)	incl	
Sales Tax (3% of EC)	incl	
Freight (5% of EC)	incl	
Subtotal, Purchased Equipment Cost (PEC)	$5,825,073	B
Direct Installation Costs		
Foundation (6% of PEC)	Incl	
Supports (6% of PEC)	Incl	
Handling and Erection (40% of PEC)	Incl	
Electrical (1% of PEC)	Incl	
Piping (30% of PEC)	Incl	
Insulation for Ductwork (1% of PEC)	Incl	
Painting (1% of PEC)	Incl	
Turnkey Installation	$1,931,081	
Site Preparation	N/A	No data
Buildings	N/A	No data
Total Direct Cost	**$7,756,154**	
Indirect Costs		
Engineering (10% of PEC)	$582,507	CONTROL COST MANUAL - EPA/452/B-02-001 (CCM), Section 5.1, Chapter 1, Table 1.3
Construction and Field Expense (10% of PEC)	$582,507	CCM, Section 5.1, Chapter 1, Table 1.3
Contractor Fees (10% of PEC)	$582,507	CCM, Section 5.1, Chapter 1, Table 1.3
Start-up (1% of PEC)	$58,251	CCM, Section 5.1, Chapter 1, Table 1.3
Performance Test (1% of PEC)	$58,251	CCM, Section 5.1, Chapter 1, Table 1.3
Contingencies (3% of PEC)	$174,752	CCM, Section 5.1, Chapter 1, Table 1.3
Total Indirect Cost	**$2,038,775**	
Total Capital Investment (TCI) (2010 $)	**$9,794,930**	
Direct Annual Costs		
Hours per Year (330 days per year, 24 hours per day)	8,040	
Operating Labor		
Man-hrs	3,840	Based on Turbosonic system
Rate	$50	Based on Turbosonic system
Subtotal, Operating Labor	$192,000	
Maintenance		
Maintenance	$200,000	Based on Turbosonic system
Subtotal, Maintenance	$200,000	
Utilities		
Electricity		
Demand (kW)	40.84	Based on Turbosonic system - 377,600 kw-hr
Cost ($/kW-hr)	$0.0535	Based on Turbosonic system - assumed $0.07/kW-hr
Subtotal, Electricity	$17,556	
Hydrated Lime		
Amount Required (ton/yr)	5	Based on Turbosonic system (scaled from modeled max SO2 content of 760 lb/hr to 2.30 lb/hr)
Cost ($/ton)	$110.00	Based on Turbosonic system (profit lost to Graymont)
Subtotal, Lime	$526	
Process Water		
Amount Required (gal/yr)	67	Based on Turbosonic system (to hydrate lime). (Scaled from modeled max SO2 content of 760 lb/hr to 2.30 lb/hr).
Cost ($/ton)	$0.24	Based on Turbosonic system
Subtotal, Lime	$16	
Subtotal, Utilities	$18,098	
Total Direct Annual Costs (2010 $)	**$410,098**	
Indirect Annual Costs		
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)	$235,525	
Administrative (2% TCI)	$195,899	0.02 TCI, CCM, Sec 5.1, Ch 1, Table 1.4
Property Tax (1% TCI)	$97,949	0.01 TCI, CCM, Sec 5.1, Ch 1, Table 1.4
Insurance (1% TCI)	$97,949	0.01 TCI, CCM, Sec 5.1, Ch 1, Table 1.4
Capital Recovery (20 year life, 4.75 percent interest)	$769,396	CCM, Sec 1, Ch 2, Eqn 2.8a
Total Indirect Annual Cost (2010 $)	**$1,396,719**	
Total Annualized Cost (2018 $)	**$1,978,379**	2011 Estimate scaled by CEPCI, from 2010 $ (year of the quote) to 2018 $ (most recently published year for index).
Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)	**0.35**	
Pollutant Removed (tons SO_2/yr) 90% removal per vendor	**0.3**	Assumes 95% control equipment uptime
Cost Per Ton of Pollutant Removed	**$6,681,060**	

Table B-4. Semi-Dry Scrubber Cost Calculations for Kiln 3

			Notes
Direct Costs			
Purchased Equipment Costs			
	Scrubber Unit	$7,215,103	($5,775,000 from Turbosonic system Quote 2010 for 69,000 acfm @ 300 °F, scaled according to 0.6 power rule)
	Instrumentation (10% of EC)	incl	
	Sales Tax (3% of EC)	incl	
	Freight (5% of EC)	incl	
	Subtotal, Purchased Equipment Cost (PEC)	$7,215,103	
Direct Installation Costs			
	Foundation (6% of PEC)	Incl	
	Supports (6% of PEC)	Incl	
	Handling and Erection (40% of PEC)	Incl	
	Electrical (1% of PEC)	Incl	
	Piping (30% of PEC)	Incl	
	Insulation for Ductwork (1% of PEC)	Incl	
	Painting (1% of PEC)	Incl	
	Turnkey Installation	$1,931,081	
Site Preparation		N/A	No data
Buildings		N/A	No data
	Total Direct Cost	**$9,146,184**	
Indirect Costs			
	Engineering (10% of PEC)	$721,510	CONTROL COST MANUAL - EPA/452/B-02-001 (CCM), Section 5.1, Chapter 1, Table 1.3
	Construction and Field Expense (10% of PEC)	$721,510	CCM, Section 5.1, Chapter 1, Table 1.3
	Contractor Fees (10% of PEC)	$721,510	CCM, Section 5.1, Chapter 1, Table 1.3
	Start-up (1% of PEC)	$72,151	CCM, Section 5.1, Chapter 1, Table 1.3
	Performance Test (1% of PEC)	$72,151	CCM, Section 5.1, Chapter 1, Table 1.3
	Contingencies (3% of PEC)	$216,453	CCM, Section 5.1, Chapter 1, Table 1.3
	Total Indirect Cost	**$2,525,286**	
	Total Capital Investment (TCI) (2010 $)	**$11,671,470**	
Direct Annual Costs			
Hours per Year	(330 days per year, 24 hours per day)	8,040	
Operating Labor			
	Man-hrs	3,840	Based on Turbosonic system
	Rate	$50	Based on Turbosonic system
	Subtotal, Operating Labor	$192,000	
Maintenance			
	Maintenance	$200,000	Based on Turbosonic system
	Subtotal, Maintenance	$200,000	
Utilities			
	Electricity		
	Demand (kW)	40.84	Based on Turbosonic system - 377,600 kw-hr
	Cost ($/kW-hr)	$0.0535	Based on Turbosonic system - assumed $0.07/kW-hr
	Subtotal, Electricity	$17,556	
	Hydrated Lime		
	Amount Required (ton/yr)	7	Based on Turbosonic system (scaled from modeled max SO2 content of 760 lb/hr to 3.48 lb/hr)
	Cost ($/ton)	$110.00	Based on Turbosonic system (profit lost to Graymont)
	Subtotal, Lime	$796	
	Process Water		
	Amount Required (gal/yr)	102	Based on Turbosonic system (to hydrate lime). (Scaled from modeled max SO2 content of 760 lb/hr to 3.48 lb/hr).
	Cost ($/ton)	$0.24	Based on Turbosonic system
	Subtotal, Lime	$25	
	Subtotal, Utilities	$18,376	
	Total Direct Annual Costs (2010 $)	**$410,376**	
Indirect Annual Costs			
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)		$235,692	
Administrative (2% TCI)		$233,429	0.02 TCI, CCM, Sec 5.1, Ch 1, Table 1.4
Property Tax (1% TCI)		$116,715	0.01 TCI, CCM, Sec 5.1, Ch 1, Table 1.4
Insurance (1% TCI)		$116,715	0.01 TCI, CCM, Sec 5.1, Ch 1, Table 1.4
Capital Recovery	(20 year life, 4.75 percent interest)	$916,799	CCM, Sec 1, Ch 2, Eqn 2.8a
	Total Indirect Annual Cost (2010 $)	**$1,619,351**	
	Total Annualized Cost (2018 $)	**$2,222,455**	2011 Estimate scaled by CEPCI, from 2010 $ (year of the quote) to 2018 $ (most recently published year for index).
	Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)	**3.5**	
	Pollutant Removed (tons SO_2/yr) 90% removal per vendor	**3.0**	Assumes 95% control equipment uptime
	Cost Per Ton of Pollutant Removed	**$739,168**	
	Total Annualized Cost for both Kilns	**$4,444,911**	

APPENDIX C : NO_X CONTROL COST CALCULATIONS

Table C-1. Summary of SNCR Costs

Kiln	Total Capital Investment	Annual Cost	Tons NO_X In	Tons NO_X Reduced	Cost Effectiveness ($/ton reduced)
1	$5,607,978	$539,413	135.30	24	$22,048.17
2	$6,173,878	$597,980	173.07	31	$19,107.94
3	$7,396,811	$719,345	206.88	37	$19,229.49
Total	$19,178,666	$1,856,738	515.25	93	$19,928.82

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

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. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 155.3 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 11,596 Btu/lb

What is the estimated actual annual fuel consumption? 49,224,000 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 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: Bituminous

Enter the sulfur content (%S) = 1.84 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

*The sulfur content of 1.84% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash): 9.23 percent by weight

*The ash content of 9.23% is a default value. See below for data source. Enter actual value, if known.

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.

	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})	330	days	Plant Elevation	5520 Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.47	lb/MMBtu		
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.38	lb/MMBtu		
Estimated Normalized Stoichiometric Ratio (NSR)	0.70			

Concentration of reagent as stored (C_{stored})	29	Percent
Density of reagent as stored (ρ_{stored})	56	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

Densities of typical SNCR 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 SNCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1	Enter the CEPCI value for 2018 — 541.7 2016 CEPCI — CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	4.75	Percent
Fuel ($Cost_{fuel}$)	3.36	\$/MMBtu
Reagent ($Cost_{reag}$)	0.33	\$/gallon for a 29 percent solution of ammonia
Water ($Cost_{water}$)	0.0010	\$/gallon
Electricity ($Cost_{elect}$)	0.0609	\$/kWh
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	\$/ton*

* 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	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)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	https://prd-wret.s3-us-west-2.amazonaws.com/assets/palladium/production/atoms/files/mcs-2019-nitro.pdf
Water Cost ($/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.	http://cms4.revize.com/revize/elkonv/Water_Rates.pdf
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	2.40	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.	EIA data - 2019 average price of coal for "other industrial" in Nevada. https://www.eia.gov/coal/data/browser/
Ash Disposal Cost ($/ton)	48.8	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.	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the 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/.	
Percent ash content for Coal (% weight)	9.23	Average ash content based on U.S. coal data for 2016 compiled by the 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/.	
Higher Heating Value (HHV) (Btu/lb)	11,841	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/.	Heat content of coal for "Other industrial" in Nevada, 2018. https://www.eia.gov/coal/data/browser/#/topic/22?agg=0,1&geo=00000000002&sec=vs&freq=A&start=2002&end=2018&ctype=map&ltype=pin&rtype=s&pin=&rse=0&maptype=0
Interest Rate (%)	5.5	Default bank prime rate	Bank prime loan as of 12/5/19

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) =	HHV x Max. Fuel Rate =	155	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	117,314,000	lbs/Year	
Actual Annual fuel consumption (Mactual) =		49,224,000	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.38	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	3323	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	20	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	14.72	lb/hour	
Total NO_x removed per year =	$(NOx_{in} \times EF \times Q_B \times t_{op})/2000$ =	24.47	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)	1.04		Averaged the three options for approximation
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	> 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.22		
Atmospheric pressure at 5520 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	12.0	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* 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 =	56 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)	19	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	65	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	8.7	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	3,000	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	0.0786

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	2.4	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	15	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.15	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x 1×10^6)/HHV =	1.2	lb/hour

Cost Estimate

Graymont Pilot Peak Kiln 1

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 ($SNCR_{cost}$) =	$1,480,291 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$1,009,155 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,824,384 in 2018 dollars
Total Capital Investment (TCI) =	$5,607,978 in 2018 dollars

* This factor applies because the boiler burns 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 ($SNCR_{cost}$) =	$1,480,291 in 2018 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}) =	$1,009,155 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$1,824,384 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$96,102 in 2018 dollars
Indirect Annual Costs (IDAC) =	$443,311 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$539,413 in 2018 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 =	$84,120 in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$9,633 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$487 in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$50 in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$1,713 in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$99 in 2018 dollars
Direct Annual Cost =		$96,102 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,524 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$440,787 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$443,311 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$539,413 per year in 2018 dollars
NOx Removed =	24 tons/year
Cost Effectiveness =	$22,048.12 per ton of NOx removed in 2018 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

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. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 191.7 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 11,596 Btu/lb

What is the estimated actual annual fuel consumption? 82,299,000 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 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: Bituminous

Enter the sulfur content (%S) = 1.84 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

*The sulfur content of 1.84% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash): 9.23 percent by weight

*The ash content of 9.23% is a default value. See below for data source. Enter actual value, if known.

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.

	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})	330	days	
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.36	lb/MMBtu	
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.29	lb/MMBtu	
Estimated Normalized Stoichiometric Ratio (NSR)	0.79		
Concentration of reagent as stored (C_{stored})	29	Percent	
Density of reagent as stored (ρ_{stored})	56	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		

Plant Elevation: 5520 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	2018			
CEPCI for 2018	603.1	Enter the CEPCI value for 2018	541.7	2016 CEPCI
Annual Interest Rate (i)	4.75	Percent		
Fuel ($Cost_{fuel}$)	3.36	$/MMBtu		
Reagent ($Cost_{reag}$)	0.33	$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0010	$/gallon		
Electricity ($Cost_{elect}$)	0.0609	$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

* 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	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)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	https://prd-wret.s3-us-west-2.amazonaws.com/assets/palladium/production/atoms/files/mcs-2019-nitro.pdf
Water Cost ($/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.	http://cms4.revize.com/revize/elkonv/Water_Rates.pdf
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	2.40	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.	EIA data - 2019 average price of coal for "other industrial" in Nevada. https://www.eia.gov/coal/data/browser/
Ash Disposal Cost ($/ton)	48.8	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.	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the 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/.	
Percent ash content for Coal (% weight)	9.23	Average ash content based on U.S. coal data for 2016 compiled by the 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/.	
Higher Heating Value (HHV) (Btu/lb)	11,841	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/.	Heat content of coal for "Other industrial" in Nevada, 2018. https://www.eia.gov/coal/data/browser/#/topic/22?agg=0,1&geo=00000000002&sec=vs&freq=A&start=2002&end=2018&ctype=map&ltype=pin&rtype=s&pin=&rse=0&maptype=0
Interest Rate (%)	5.5	Default bank prime rate	Bank prime loan as of 12/5/19

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) =	HHV x Max. Fuel Rate =	192	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	144,833,000	lbs/Year	
Actual Annual fuel consumption (Mactual) =		82,299,000	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.51	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4500	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	20	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	13.91	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	31.29	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)	1.04		Averaged the three options for approximation
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	> 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.22		
Atmospheric pressure at 5520 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	12.0	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* 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 =	56 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)	20	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	70	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	9.3	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	3,200	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	0.0786

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	2.6	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x $((C_{stored}/C_{inj}) - 1)$ =	16	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	0.16	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1\times10^6)/HHV$ =	1.3	lb/hour

Cost Estimate

Graymont Pilot Peak Kiln 2

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 ($SNCR_{cost}$) =	$1,617,277 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$1,189,437 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,942,423 in 2018 dollars
Total Capital Investment (TCI) =	$6,173,878 in 2018 dollars

* This factor applies because the boiler burns 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 ($SNCR_{cost}$) =	$1,617,277 in 2018 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}) =	$1,189,437 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/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}) =	$1,942,423 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$109,935 in 2018 dollars
Indirect Annual Costs (IDAC) =	$488,045 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$597,980 in 2018 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 =	$92,608 in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$13,929 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$704 in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$73 in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$2,477 in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$143 in 2018 dollars
Direct Annual Cost =		$109,935 in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$2,778 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$485,267 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$488,045 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$597,980 per year in 2018 dollars
NOx Removed =	31 tons/year
Cost Effectiveness =	$19,108 per ton of NOx removed in 2018 dollars

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Industrial

What type of fuel does the unit burn? Coal

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. 1.5

* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)? 276.5 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 11,596 Btu/lb

What is the estimated actual annual fuel consumption? 127,038,000 lbs/Year

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10 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: Bituminous

Enter the sulfur content (%S) = 1.84 percent by weight

or

Select the appropriate SO_2 emission rate: Not Applicable

*The sulfur content of 1.84% is a default value. See below for data source. Enter actual value, if known.

Ash content (%Ash): 9.23 percent by weight

*The ash content of 9.23% is a default value. See below for data source. Enter actual value, if known.

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.

	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})	330 days	Plant Elevation	5520 Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.28 lb/MMBtu		
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.22 lb/MMBtu		
Estimated Normalized Stoichiometric Ratio (NSR)	0.90		

Concentration of reagent as stored (C_{stored})	29 Percent
Density of reagent as stored (ρ_{stored})	56 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	2018		
CEPCI for 2018	603.1 Enter the CEPCI value for 2018	541.7	2016 CEPCI
Annual Interest Rate (i)	4.75 Percent		
Fuel ($Cost_{fuel}$)	3.36 \$/MMBtu		
Reagent ($Cost_{reag}$)	0.33 \$/gallon for a 29 percent solution of ammonia		
Water ($Cost_{water}$)	0.0010 \$/gallon		
Electricity ($Cost_{elect}$)	0.0609 \$/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80 \$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

* 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	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)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	https://prd-wret.s3-us-west-2.amazonaws.com/assets/palladium/production/atoms/files/mcs-2019-nitro.pdf
Water Cost ($/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.	http://cms4.revize.com/revize/elkonv/Water_Rates.pdf
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
Fuel Cost ($/MMBtu)	2.40	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.	EIA data - 2019 average price of coal for "other industrial" in Nevada. https://www.eia.gov/coal/data/browser/
Ash Disposal Cost ($/ton)	48.8	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.	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the 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/.	
Percent ash content for Coal (% weight)	9.23	Average ash content based on U.S. coal data for 2016 compiled by the 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/.	
Higher Heating Value (HHV) (Btu/lb)	11,841	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/.	Heat content of coal for "Other industrial" in Nevada, 2018. https://www.eia.gov/coal/data/browser/#/topic/22?agg=0,1&geo=00000000002&sec=vs&freq=A&start=2002&end=2018&ctype=map&ltype=pin&rtype=s&pin=&rse=0&maptype=0
Interest Rate (%)	5.5	Default bank prime rate	Bank prime loan as of 12/5/19

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) =	HHV x Max. Fuel Rate =	276	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	208,872,000	lbs/Year	
Actual Annual fuel consumption (Mactual) =		127,038,000	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.55	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	4817	hours	
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	20	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	15.53	lb/hour	
Total NO_x removed per year =	$(NOx_{in}$ x EF x Q_B x $t_{op})/2000$ =	37.41	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)	1.04		Averaged the three options for approximation
SO_2 Emission rate =	$(\%S/100)x(64/32)*(1x10^6)/HHV$ =	> 3	lbs/MMBtu	
Elevation Factor (ELEVF) =	14.7 psia/P =	1.22		
Atmospheric pressure at 5520 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	12.0	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* 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 = 56 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)	26	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	89	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	11.9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	4,000	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	0.0786

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	3.3	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	20	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x $((1/C_{inj})-1)$ =	0.21	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	1.7	lb/hour

Cost Estimate

Graymont Pilot Peak Kiln 3

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 ($SNCR_{cost}$) =	$1,886,122 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$1,582,600 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$2,221,132 in 2018 dollars
Total Capital Investment (TCI) =	$7,396,811 in 2018 dollars

* This factor applies because the boiler burns 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 ($SNCR_{cost}$) =	$1,886,122 in 2018 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}) =	$1,582,600 in 2018 dollars

* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/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}) =	$2,221,132 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$134,627	in 2018 dollars
Indirect Annual Costs (IDAC) =	$584,718	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$719,345	in 2018 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 =	$110,952	in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$19,033	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$962	in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$100	in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$3,385	in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$196	in 2018 dollars
Direct Annual Cost =		$134,627	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,329	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$581,389	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$584,718	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$719,345	per year in 2018 dollars
NOx Removed =	37	tons/year
Cost Effectiveness =	$19,229	per ton of NOx removed in 2018 dollars

APPENDIX D : MISCELLANEOUS PM_{10} EMISSION SOURCES AND CONTROLS

The following table summarizes the non-kiln PM_{10} emissions sources at the Pilot Peak facility and the emissions reduction options currently used at each source.

Table D-1. Summary of PM_{10} Emission Sources and Controls

Emission Unit System ID	Emission Unit Description	Emission Control/Reduction Method
01	Limestone Truck Dump	Water Sprays, Enclosure
02	Primary Crushing and Screening Circuit (D-1)	Baghouse D-1
03	Secondary Screening Circuit (D-311)	Baghouse D-311
05	Limestone Quarry Conveyance Transfers	Water Sprays
06	Lime Plant Conveyance Transfers	Underground Transfers
07	Lime Plant Stone Dressing Screens (Kilns 1 & 2) (D-10)	Baghouse D-10
08	Lime Plant Stone Dressing Screen	Baghouse D-317
09	Lime Plant Stone Surge Bins N-19 (Kiln 1) and N-219 (Kiln 2) (D-19)	Baghouse D-19
11	Kiln 1 Coal Handling 1 Circuit	Enclosure
12	Kiln 1 Coal Silo T-90 (D-91)	Baghouse D-91
13a	Kiln #2 Circuit (D-282)	Baghouse D-282
14	Kiln 2 Coal Handling Circuit	Enclosure
15	Kiln 2 Coal Silo T-290 (D-291)	Baghouse D-291
16	Lime Plant Stone Feed to Kiln 3 (D-382)	Baghouse D-382
18	Kiln 3 Coal Handling Circuit	Good Operating Practices, Enclosure
19	Kiln 3 Coal Silo T-391 (D-391)	Baghouse D-391
20	Product Lime Loadout from Kiln 1 (D-82)	Baghouse D-82
21	Product Lime Loadout from Kiln 2 (DC-230)	Baghouse DC-230
22	Product Lime Loadout from Kiln 2 (DC-30)	Baghouse DC-30
23	Kiln 1 & 2 Cyclone/Baghouse Fines Silo Discharge	Enclosure
24	Kiln 1 & 2 Cyclone/Baghouse Coll. Prod. Loadout	Baghouse D-89
25	Kiln 1 & 2 Baghouse Fines Silo Discharge System	Baghouse D-11
26	Kiln 3 Baghouse Collection Product Loadout	Baghouse D-388
27	Kiln 3 Baghouse Fines Discharge System (D-389)	Baghouse D-389
28	Kiln 3 Baghouse Fines Discharge System	Enclosure
29	Hydrate Plant Surge Bin (D-1101)	Baghouse D-1101
30	Hydrate Plant Hydrator	Baghouse D-1101
31	Hydrate Plant Lime Transfer (DC-1132)	Baghouse DC-1132
32	Hydrate Plant Lime Transfer to Silo T-1140	Baghouse D-1140
33	Hydrate Plant Lime Transfer to Silo T-1141	Baghouse D-1141
34	Hydrate Silos Loadout	Baghouse D-1142
35	Product Lime Kiln 3 - Control Device 1 (D-331)	Baghouse D-331
36	Product Lime Kiln 3 - Control Device 2 (D-333)	Baghouse D-333
37	Product Lime Kiln 3 - Control Device 3 (D-343)	Baghouse D-343
38	Product Lime Kiln 3 - Control Device 4 (D-361)	Baghouse D-361
41	Kiln #1 Auxiliary Drive Motor	Good Operating Practices
42	Kiln #2 Auxiliary Drive Motor	Good Operating Practices
43	Kiln #3 Auxiliary Drive Motor	Good Operating Practices

Emission Unit System ID	Emission Unit Description	Emission Control/Reduction Method
44	Emergency Fire Pump	Good Operating Practices
45	Truck Unloading	Enclosure
46	Railcar Loading	Baghouse
47	Fine Dust Surge Bin N-80 Transfer to Truck	Good Operating Practices
48	Fine Dust Surge Bin N-280 Transfer to Truck	Good Operating Practices
49	Fine Dust Surge Bin N-380 Transfer to Truck	Good Operating Practices

Appendix B.2.c - Response Letter 1

GRAYMONT

November 13, 2020

Mr. Steven McNeece
Environmental Scientist
Nevada Division of Environmental Protection
Department of Conservation and Natural Resources
901 S. Stewart Street, Suite 4001
Carson City, NV 89701
smcneece@ndep.nv.gov

RE: Graymont Pilot Peak Response to Federal Land Managers Comments on Four-Factor Analysis for Regional Haze

Dear Mr. McNeece:

This letter is provided by Graymont Western Lime, Inc. (Graymont) in response to comments received on October 20, 2020 from the Nevada Division of Environmental Protection (NDEP) and the Federal Land Managers (FLMs) on Graymont's updated regional haze four-factor analysis submitted for their Pilot Peak plant. The letter addresses the questions raised by NDEP and the FLMs regarding the feasibility of selective non-catalytic reduction (SNCR), the use of a control efficiency of 20% in cost calculations for SNCR, and the use of a retrofit factor of 1.5 in the development of the SNCR costs.

SNCR FEASIBILITY

As discussed in the four-factor analysis, the lime industry has a severely limited track record of successfully implementing mid-kiln SNCR for a lime kiln. The RACT/BACT/LAER Clearinghouse (RBLC) database includes only one instance of two lime kilns that were permitted with SNCR as control for NO_X emissions.[1] The permit documents indicate that after conducting 24 months of evaluation with the SNCR, a lower limit would be established that takes into account the control of NO_X emissions achieved by the SNCR (unless it is demonstrated to not provide effective control or result in unacceptable consequences). Updated permit files have not

[1] RBLC Search results are provided in Appendix A of the four-factor analysis, see the entry for the Mississippi Lime Company. This entry represents the permit considered by the Illinois EPA in 2015, referenced in the FLMs' second comment on technical feasibility (a comment by Lhoist on the Mississippi Lime Company permit that references the Lhoist Nelson plant).

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included a reduced permit limit, and there is no publicly available evidence of the trial results. These new kilns were never constructed, therefore this permit does not indicate that SNCR can successfully be implemented for a lime kiln retrofit in a way that is not cost prohibitive. An aerial image of the Mississippi Lime facility is provided below, taken in May of 2019, where no kiln exists.

Figure 1. Aerial Image of Mississippi Lime Facility Referenced in RBLC Database

Graymont acknowledged in the regional haze analysis that there is limited precedent for SNCR not listed in the RBLC by one company: the installation of SNCR by Lhoist, as mentioned in the comments from NDEP and the FLMs. Graymont agrees with the assertion that the EPA determined SNCR was technically feasible for Lhoist's Nelson kilns; however, there is no publicly available information for Graymont to determine whether Lhoist successfully implemented the controls and achieved the anticipated level of NO_X emissions control.

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The second example cited by the FLMs does not represent an additional example of SNCR installation on a lime kiln – this comment was submitted by Lhoist and referenced the same example at Lhoist's Nelson, AZ facility. This comment was submitted as part of the permitting process for the Mississippi Lime Company facility that is referenced in the RBLC database, which was never completed. Further, in Lhoist's comment there is no information regarding the success of the implementation of the SNCR technology mid-kiln in achieving the discussed control efficiency, and there is no information indicating that this installation represents a cost-effective method of NO_X emissions control. The Illinois EPA, in their determination that SNCR was feasible for the purposes of PSD-BACT for Mississippi Lime, states directly:[2]

> *While Lhoist's comments provide data for NOx emissions from the kilns at its O'Neal[3] facility, this data is only sufficient to generally confirm the availability and feasibility of SNCR technology. It should not be used as a basis to set a BACT limit for the proposed kilns. This is because Lhoist has not provided detailed information on how SNCR technology has been adapted for use on the kilns at its O'Neal plant. <u>Moreover, even if such information had been provided, Lhoist has not shown that such approach(s) are generally applicable to any new lime kiln or, considering proprietary aspects of the approaches, would be available to Mississippi Lime.</u>*

Based on the underlined portion of this determination, the implementation of SNCR on lime kilns should not considered an available technology for the purposes of the regional haze program. As stated in the four-factor analysis, 40 CFR Subpart 51 Appendix Y defines availability, a prerequisite for determining whether a technology could be applied for the Regional Haze Rule, "a technology is considered 'available' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term." Inherent in the determination made by the Illinois EPA for PSD-BACT (a program with different and more stringent requirements than the regional haze program) is the conclusion that this technology is not considered commercially available and thus should be precluded from consideration.

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[2] Illinois Environmental Protection Agency Bureau of Air, "Responsiveness Summary for the Public Comment Period on the Issuance of A Construction Permit/PSD Approval for Mississippi Lime Company to Construct a Lime Plant in Prairie du Rocher, Illinois," Page 23. (September 2015). http://www.epa.state.il.us/public-notices/2014/mississippi-lime/responsiveness-summary.pdf

[3] Note that the original comment by Lhoist (and cited in the FLM example) related to Lhoist's Nelson facility, but later communication from Lhoist to Illinois EPA also included data related to the Lhoist O'Neal facility in Calera, Alabama.

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Furthermore, in December 2018 Wisconsin DNR concluded that SNCR is not technically feasible for either of Graymont's Eden kilns.[4] In particular, Kiln 2 is of the same type as the Pilot Peak kilns. Wisconsin DNR determined that the SNCR was not technically feasible for Graymont Eden's preheater kiln due to "the very short residence time available for the reduction of NOx, the need for a supplemental combustion source, and the low NOx emission rate already being required from the kiln as BACT – as well as the uncertainties surrounding the amount of emission reduction that the technology could achieve on this particular kiln."[5] While SNCR may be technically feasible for the Lhoist kiln mentioned in the FLM's comment, this determination indicates that SNCR should not be considered technically feasible for all lime kilns, and there is uncertainty regarding both the feasibility and effectiveness of SNCR retrofits for lime kilns.

Nevertheless, as stated in the four-factor analysis Graymont is conservatively assuming that SNCR is a technically feasible control technology for the lime kilns at the Pilot Peak facility and has thus conducted an analysis of the retrofit costs using methods cited in the EPA's Air Pollution Control Cost Manual.

EXPECTED SNCR CONTROL EFFICIENCIES

Graymont used a control efficiency of 20% for the four-factor analysis based on Graymont's experience with SNCR evaluation at another Graymont facility. This efficiency is lower than the 50% control in the FLM comment cited by Lhoist. However, this comparison in not appropriate for two key reasons. First, Lhoist's more recent publicly available document states the expected control efficiency range is 25-50%.[6] The 25% control efficiency was used by Lhoist and accepted by Utah Division of Air Quality to calculate the BACT limit.[7] This level of control is highly uncertain due to the lack of publicly available data, and Illinois EPA demonstrated their lack of confidence in the efficiency claims by Lhoist in the way the Mississippi Lime Company permit was written. The permit initially required SNCR but set the BACT NO_X limit equal to the BACT level at another new lime kiln without SNCR (essentially assuming an SNCR control efficiency of 0%) and included a requirement to

[4] Wisconsin Department of Natural Resources, "Preliminary Determination, FID No. 420042480 Permit Nos. 18-RAB010, 420042480-P31" (December 2018). Page 38.
Note the "Preliminary Determination" accompanies the draft permit and is considered the appropriate technical documentation for the final permit. The NO_X BACT decision related to the SNCR technical feasibility did not change between the draft permit (December 2018) and the final permit (March 2019)
[5] Ibid.
[6] Utah Division of Air Quality, "$PM_{2.5}$ SIP Evaluation Report: Lhoist North America – Grantsville Facility," PDF Page 12. (July 2018). https://documents.deq.utah.gov/air-quality/pm25-serious-sip/DAQ-2018-007681.pdf
[7] Ibid, Pages 21 and 3-18 of Appendix A (PDF pages 22 and 57).

reevaluate the permit limits for NO_X emissions after actual implementation and testing could resolve the uncertainty around the achievable NO_X emission control efficiencies. Second, a significant driver of the control efficiency is the uncontrolled NO_X concentrations. Per the EPA Control Cost Manual, “SNCR is not suitable for sources where the residence time is too short, temperatures are too low, NO_X concentrations are low, the reagent would contaminate the product, or no suitable location exists for installing reagent injection ports.” Though Graymont’s lower uncontrolled NO_X emission rates may not render SNCR entirely ineffective, the achievable control efficiency is expected to be much lower than the Nelson lime kilns because of Nelson’s higher uncontrolled NO_X emission rates. As shown in Table 1 below, the Graymont Pilot Peak kilns’ uncontrolled permitted NO_X levels are considerably lower than Lhoist’s Nelson, AZ facility (4.0 – 4.8 lb/ton compared to 7.59 and 5.21 lb/ton[8]).

Table 1. Current Pilot Peak NO_X Limits

Kiln	NO_X Permit Limit [a] (lb/hr)	Production Rate Limit (ton/hr)	Calculated Equivalent NO_X Limit [b] (lb/ton)
Kiln 1	120	25	4.8
Kiln 2	160	33.3	4.8
Kiln 3	200	50	4.0

a. Pilot Peak’s NO_X emission limits are provided on an hourly basis, as well as a separate limit on a 12-month rolling basis.
b. Pilot Peak does not have a permit limit on a lb NO_X per ton of lime basis. These values are calculated solely for the purpose of comparison to cited Lhoist Nelson plant values and should not be construed as representing a permitted limit for the Pilot Peak facility.

Using the NO_X emission levels required for the Lhoist Nelson and Granstville facilities as a benchmark (3.27 lb/ton for combined emissions from Nelson Kiln 1 and Kiln 2 and 3.41 lb/ton for Grantsville, averaging 3.34 lb/ton), the calculated control efficiency from Graymont’s uncontrolled NO_X emission limit to 3.34 lb/ton would result in a control efficiency of approximately 30% for Kilns 1 and 2 and 17% for Kiln 3. Starting from these efficiencies, they should be adjusted downward to take into account added uncertainty for site-specific factors such as shorter residence time or less favorable temperatures and the lack of commercial availability of the control technology for use on lime kilns. Assuming an uncertainty range of ±30% of the NO_X reduction levels calculated above, the resulting control efficiencies are 21% for Kilns1 and 2 and 12% for Kiln 3, with an average of 18%. Therefore, the use of an

[8] Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Proposed Rule. Federal Register Vol. 79, No. 32 (February 18, 2014). Table 19. https://www.govinfo.gov/content/pkg/FR-2014-02-18/html/2014-02714.htm

anticipated control efficiency of 20% is appropriate for the estimates used in Graymont's four-factor analysis.

RETROFIT FACTOR

Graymont used a retrofit factor of 1.5 to represent technical uncertainties associated with the retrofitting of the Pilot Peak lime kilns for SNCR implementation. In NDEP's and the FLMs' comments to Graymont, it is stated that "SNCR technology does not typically yield retrofit factors above 1 as it does not require the installation of a catalyst and doesn't require a tremendous amount of space." However, the EPA Control Cost Manual does not explicitly include this statement. This summary of the retrofit factor does not apply in Graymont's case because the EPA Control Cost Manual refers to the difference in costs for retrofitting an existing boiler and installing on a new boiler. A retrofit factor of 1 should be used for retrofit projects of common difficulty, as compared to the retrofit of SNCR on a boiler (for which the cost calculations were originally developed). SNCR installation on boilers has been achieved broadly and is considered common on a typical boiler; however, SNCR installation on lime kilns is not common. Per the EPA, the cost methodology was originally developed for use with boilers, and calculations should be tailored to the source being controlled.[9] Given that Lhoist's proprietary technology represents the only known successful implementation of SNCR as a retrofit to a lime kiln, the details of which are not publicly available, the retrofit on a non-Lhoist lime kiln cannot be considered "average" relative to a boiler retrofit. SNCR retrofits for utility boilers are far more common, and the anticipated costs are therefore well-established when compared to lime kiln retrofits.

Per the EPA Control Cost manual, it is "not uncommon to see retrofit factors of much greater magnitude" than 1.5 being used for complicated systems. Therefore, a factor even higher than 1.5 could be appropriate. Graymont acknowledges that specific conditions traditionally requiring a retrofit factor such as complex ducting or space constraints may not impact the retrofit of the kiln in the same way that it would a small boiler. However, in the context of the factors outlined by William Vatavuk in the book discussed in the FLMs' comments, "Estimating Costs of Air Pollution Control," a factor of 1.5 is appropriate to account for many of the anticipated higher costs are associated for additional engineering involved in designing a system for the lime kiln, a retrofit that is not well-established in the industry.

[9] EPA Air Pollution Control Cost Manual, Section 4, Chapter 1, "Selective Noncatalytic Reduction" (April 2019). Page 1-6. epa.gov/sites/production/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf

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The 1.5 retrofit factor is intended to account for the added engineering costs, as well as contingencies associated with retrofitting the lime kilns with a technology that has only one known implementation in the industry.[10] Per the control cost manual, contingencies for mature control technologies (let alone relatively unproven implementations of control technologies) can have contingencies as high as 15%.[11]

Per Table 2.2 of Estimating Costs of Air Pollution Control, engineering and supervision range between 10-20% of total purchased equipment costs and contingencies can be approximated for study-level estimates at 3% of total purchased equipment costs. Retrofit adjustment factors are then applied to each fraction of cost based on Table 2.3 of Estimating Costs of Air Pollution Control.[12] For the purposes of this assessment, the engineering and supervision required are assumed to be equivalent to those of prototype equipment (adjustment factor of 3) because there is no publicly available information on implementation and engineering required to successfully install SNCR on a lime kiln. For contingencies, pilot tests will be required to obtain efficiencies and operating specification guarantees (an adjustment factor of 5 to 10) for the same reason (the only implemented examples of SNCR in the lime industry do not have publicly available information).

Equation:

$$\text{Retrofit Factor} = 1 + (\text{Engineering Cost})(\text{Engineering Adjustment Factor}) + (\text{Contingencies})(\text{Contingency Adjustment Factor})$$

Minimum Factor:

$$\text{Retrofit Factor} = 1 + (0.1)(3) + (0.03)(5) = 1.45$$

Maximum Factor:

$$\text{Retrofit Factor} = 1 + (0.2)(3) + (0.03)(10) = 1.9$$

Applying the retrofit factor derivation using the equation above and accounting only for engineering and contingencies, the range of potential appropriate retrofit factors is 1.45-1.9. Therefore, Graymont maintains that a retrofit factor of 1.5 is appropriate

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[10] Note that the EPA's control cost manual calculations spreadsheets do not account for contingency beyond those anticipated for a typical SNCR retrofit, and thus the retrofit factor is used by Graymont both to quantify anticipated complications related to the retrofit itself and contingencies associated with retrofitting the lime kilns with SNCR, which has severely limited use in the industry.

[11] EPA Air Pollution Control Cost Manual, Section 1, Chapter 2, "Cost Estimation: Concepts and Methodology" (April 2019). Page 30. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[12] Vatavuk, William. "Estimating Costs of Air Pollution Control," *Lewis Publishers,* 1990. Pages 20-22. ISBN: 0-87371-142-4.

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(and even conservatively low) for the evaluation of SNCR for the lime kilns at the Pilot Peak facility.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call me at 505.286.6026.

Sincerely,

GRAYMONT PILOT PEAK

Nate Stettler

Nate Stettler
Senior HSE Specialist and Lead Auditor

Attachments

cc: Sigurd Jaunarajs, NDEP
Terry McIntyre, Graymont
John Maitland, Graymont
Anna Henolson, Trinity Consultants
Sam Najmolhoda, Trinity Consultants

Appendix B.2.d - Response Letter 2

GRAYMONT

April 16, 2021

Mr. Steven McNeece *(VIA Electronic Mail)*
Environmental Scientist
Nevada Division of Environmental Protection
Department of Conservation and Natural Resources
901 S. Stewart Street, Suite 4001
Carson City, NV 89701
smcneece@ndep.nv.gov

RE: Pilot Peak Response to NDEP Request for Additional Information
Graymont Western US, Inc.

Dear Mr. McNeece:

Graymont Western US, Inc. (Graymont) has prepared this letter in response to comments received on January 28, 2021 from the Nevada Division of Environmental Protection (NDEP) concerning the regional haze four-factor analysis for the Pilot Peak Plant. This letter follows an updated four-factor analysis submitted on October 19, 2020 and a subsequent response to NDEP and Federal Land Manager (FLM) comments submitted on November 13, 2020.

At NDEP's request, Graymont commissioned a Class 4 engineering cost estimate to ascertain capital and operating costs associated with installing and operating Selective Non-Catalytic Reduction (SNCR) Nitrogen Oxides (NOx) abatement systems on Pilot Peak's Kilns 1, 2 and 3. The cost estimations performed by a third party engineer indicate that the total capital cost for installation of SNCR systems at Pilot Peak exceed \$4.1 MMUSD and operating costs exceed \$3.7 MMUSD annually, resulting in a cost of \$39,803 per ton of NO_x removed based upon a 20 percent removal efficiency[1]. A factor of 20 percent was utilized based on the temperature and residence time limitations of the SNCR reaction zone for each Pilot Peak kiln combined with the Low NOx baseline concentration already achieved through use of Low NOx Burners (LNB)[2]

[1] Pilot Peak SNCR Cost Effectiveness Calculations are detailed in Appendix A
[2] Lhoist North America indicated in a November 2020 4-factor analysis that Kilns 1, 2 & 3 would be capable of a maximum NOx control of 20%.

Graymont also compared the current NO_X emissions from Pilot Peak to publicly available information for the Lhoist North America (LNA) rotary preheater kilns which utilize SCNR. We can share the following observations:

- The existing LNBs at Pilot Peak have effectively reduced the NO_X emission intensity to a level four times less than the pre-control NO_X intensity of LNA's Nelson Plant which utilizes SNCR.

- Any additive efficiency that might be gained from Pilot Peak's use of SNCR would be marginal, at best, as SNCR NOx removal efficiency is highly dependent upon the inlet NOx concentration, reaction zone temperature and residence time, All of these factors reduce the anticipated efficiency that can reasonably be assumed for the Pilot Peak Kilns 1, 2 and 3.

- Graymont identified an error in NDEP's calculation of Pilot Peak's Q/d value. When corrected, Pilot Peak's Q/d drops from 5.15 to 4.6, comfortably outside the NDEP's conservative screening threshold of 5 (and well outside the more normal screening threshold of 10).

- Consistent with the Q/d analysis, Pilot Peak's NOx emissions cannot meaningfully impact visibility at the Jarbidge Wilderness Area due to the existing low NO_X emission rate achieved by the Kilns, the chemical composition of particulate matter found to be impacting Jarbidge, intervening geographic barriers and prevailing wind patterns.

- NOx has nearly zero impact on regional haze at Jarbidge Wilderness Area as shown ammonium nitrate data from anthropogenic sources as measured by the JARB1 monitor.

- The LNA SNCR technology for rotary lime kilns is proprietary and not unconditionally commercially available to Graymont. The technology appears to be patented, adding to its cost and the uncertainty as to its technical feasibility.

- SNCR addition at Pilot Peak would have unintended negative environmental impacts and visibility disbenefits, including the generation of condensable particulate, an identified regional haze primary pollutant.

Based on Graymont's findings, requiring the installation of SNCR at Pilot Peak would be unreasonable because it would be infeasible, unnecessary and counterproductive to making reasonable progress towards the goal of preventing future, and remedying

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any existing, anthropogenic impairment of visibility in mandatory Class I Federal areas in the context of Nevada's pending Round 2 Regional Haze State Implementation Plan (RH SIP). Although Pilot Peak is not a contributor to regional haze at Jarbidge Wilderness Area (or other Class I areas), Pilot Peak's successful implementation of LNBs effectively controls NOx at the point of generation in Kilns 1, 2 and 3. These NOx rates are sufficient for inclusion in the NDEP RH SIP since they are already some of the lowest achieved in the industry and far exceed what has been deemed BART at other kilns (such as the SNCR controlled kilns at the LNA Nelson Facility).

Existing Low NOx Burners at Pilot Peak Effectively Reduce NO_X Emission Intensity

Graymont's Pilot Peak Kilns are currently equipped with LNB's that have effectively demonstrated excellent control of NOx generation during the combustion process. Table 1, below, compares the NO_X emission limits applicable to the Graymont Pilot Peak and LNA Nelson kilns. As shown, the uncontrolled NO_X emissions from the LNA Nelson plant prior to the installation of SNCR were substantially higher than the current NO_X emission levels achieved by the Graymont Pilot Peak Kilns, and even higher than the Pilot Peak emission limitations.

Table 1. Summary of NO_X Emissions from the Graymont and Lhoist Lime Kilns

Facility	Kiln	Pre-SCNR Actual Emissions [a, b] (lb/ton lime)	Current Calculated Permit Emission Limit [c] (lb/ton lime)	SNCR Permit Emission Limit [a] (lb/ton lime)
Graymont Pilot Peak	Kiln 1	2.10	4.80	--
	Kiln 2	1.30	4.80	--
	Kiln 3	1.37	4.00	--
Lhoist Nelson	Kiln 1	7.59	--	3.80
	Kiln 2	5.21	--	2.61

a. Uncontrolled emissions and the BART emission limits for the Lhoist Nelson plant kilns are obtained from the "Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Proposed Rule." Federal Register Vol. 79, No. 32 (February 18, 2014). Tables 18 and 19. https://www.govinfo.gov/content/pkg/FR-2014-02-18/html/2014-02714.htm

b. Actual emissions are based on the 2014 annual emission inventory submitted by Graymont to NDEP.

c. Note that Pilot Peak does not have a permit limit on a lb NO_X per ton of lime basis. These values are calculated solely for the purpose of comparison to cited Lhoist Nelson plant values and should not be construed as representing a permitted limit for the Pilot Peak facility.

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LNA realized this performance disparity in technologies as it too attempted to implement LNB controls at its Nelson Plant before turning to less effective SNCR. Yet, LNA was not able to make LNB work. This is explained in the 2013 Technical Support Document for Arizona's Federal Implementation Plan:

> "In 2001, LNA experimented with the installation of a bluff body LNBs on the Nelson Lime kilns. These LNB's wore out in approximately six months, impacted production, caused brick damage, and resulted in unscheduled shutdowns for the kilns. We recognize that the staged combustion principle of LNB can present operational difficulties and potential product quality issues for lime production that are not exhibited in the cement industry. At this time, however, we consider LNB to be technically infeasible for the Nelson Plan Cement (lime) kilns, since we do not have any information to suggest otherwise at this time. The technical feasibility of LNB will be re-evaluated for lime kilns in a subsequent reasonable progress planning periods."

The site- and unit-specific feasibility of LNB emission control is supported by Graymont's successful implementation of this technology on the Pilot Peak lime kilns. Graymont cannot speculate on why bluff body LNB's were unsuccessful at LNA's Nelson plant in 2001, but this failure forced LNA to advocate for use of its much less effective SNCR technology as BART in the Round 1 RH SIP process. Arizona proposed, and EPA approved, LNA's SNCR technology as BART. However, Graymont has demonstrated that bluff body LNBs can be successfully implemented on lime kilns and achieve NOx emission reductions that far exceed what might be achieved with SNCR. Plainly stated, Pilot Peak's use of LNBs far exceeds what has been deemed to be BART, at least for the LNA Nelson Plant. It would be unreasonable to require Pilot Peak to go even further in controlling NOx (i.e., beyond BART), especially when there is no evidence that such controls are needed or effective in the Nevada RH SIP (as explained below). This assertion is supported by the EPA's BART determination for the Nelson plant, where the Agency concludes that the proposed BART limit *"is consistent with the use of low-NO_X burners (LNB) and SNCR as control technologies"*[3] – indicating the emission limit would be similar for either technology. As demonstrated in the table above, Graymont can achieve

[3] Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Proposed Rule. Federal Register Vol. 79, No. 32 (February 18, 2014). Tables 18 and 19. https://www.govinfo.gov/content/pkg/FR-2014-02-18/html/2014-02714.htm

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actual emission levels on a 12-month basis with LNB technology that are lower than the levels achieved by Lhoist using SNCR.

Graymont is committed to continuing the use of LNB at Pilot Peak and achieving the attendant NOx emission reductions in the future. Further reductions from Pilot Peak are not reasonably necessary or needed to fulfill NDEP's RH SIP obligations. Indeed, EPA recently approved the District of Columbia RH SIP concluding that it was reasonable for the District to have excluded a source from even undergoing a four-factor analysis where that facility had already installed LNB and was achieving low NOx emission rates. See, 86 Fed. Reg. at 19806 (April 15, 2021).

LNB technology represents a superior level of NOx control at the point of generation as compared SNCR where, in the case of the lime industry, includes unintended negative consequences that would be experienced in the form of condensable particulate formation as a byproduct of attempting to control a higher intensity NOx source.

Additive Efficiency for Pilot Peak SNCR NOx Control Beyond LNBs would be Marginal at Best

As discussed above, Graymont has already implemented LNB control at Pilot Peak, resulting in control efficiency comparable to, or better than, SNCR control efficiencies. As indicated in both the four-factor analysis submitted by Graymont for the Pilot Peak facility and Graymont's subsequent responses to NDEP comments, the control efficiency achieved by SNCR as a retrofit technology is highly dependent on the inlet NO_X concentration, temperature of reaction zone and residence time.

Even if SNCR could provide some emission reduction for Graymont's Pilot Peak Kilns, the achievable control efficiency is expected to be much lower than the Nelson lime kilns because of Nelson's higher uncontrolled NO_X emission rates. This difference is in large part due to the successful implementation of LNB's on the Pilot Peak Kilns.

While it is difficult to ascertain what the as-built additive removal of SNCR control on top of LNB control might be, we can expect that SNCR control would be poor. From LNA's Apex plant November 2020 4-Factor submission to NDEP:

> *"….this (reported 50% NOx removal efficiency conducted at a different LNA facility) one example of SNCR installation on a preheater rotary lime kiln does not necessarily transfer to other lime kilns. Effectiveness of SNCR is highly*

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source-dependent, with a variety of factors having the potential to heavily influence the quantities of NOx controlled." …."[4]

And:

"…. When compared to the cement process, lower NOx concentrations, shorter residence times, and temperatures more frequently outside the optimal range for SNCR application yield lower control efficiencies for lime kilns. ***Therefore, a control efficiency of no more than 20% at (Apex plant) Kiln 1, 2 and 3 and no more than 50% at Kiln 4, can be guaranteed at the Facility's kilns without testing.*** *Trying to achieve a 50% removal efficiency on Kilns 1, 2 and 3 is more likely to result in ammonia slip which can cause its own health and visibility problems…."*[5]

LNA's acknowledgement that SNCR NOx removal is kiln specific is instructive for any expectation that the Pilot Peak Kilns could achieve greater than 20% NOx removal efficiency. Graymont agrees with LNA on this point.

In contrast to LNA's assertions above, in prior correspondence with NDEP, NDEP office has stated:

"…. EPA has determined SNCR as technically and economically feasible for lime kilns, and has assumed a 50% NOx reduction of Lhoist North America's Nelson facility. Based on similar configuration and age between the Pilot Peak and Nelson kilns, it is reasonable to assume that the Pilot Peak kilns are capable of achieving 50% NOx reduction through the use of SNCR. To dispute this, a site-specific vendor quote with a guaranteed control efficiency would be ideal. In the absence of this, the only alternative is to provide a robust and site-specific analysis that considers Pilot Peak's kilns and why they would not be able to achieve the 50% NOx reduction we see at the Nelson facility. As of now, the 4-factor report does not sufficiently justify a 20% reduction." [6]

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[4] REGIONAL HAZE SECOND PLANNING PERIOD FOUR-FACTOR ANALYSIS, Lhoist North America, Apex Lime Plan, Source 00003, Page 33, Trinity Consultants, March 2020, Revised June 2020, Revised November 2020.

[5] REGIONAL HAZE SECOND PLANNING PERIOD FOUR-FACTOR ANALYSIS, Lhoist North America, Apex Lime Plan, Source 00003, Page 33, Trinity Consultants, March 2020, Revised June 2020, Revised November 2020. Emphasis added.

[6] (RHR) Pilot Peak 4-Factor Analysis, email from Steven McNeece to Nate Stettler, dated October 27, 2020.

Graymont does not believe it is rational or reasonable to assume that Pilot Peak Kilns are capable of an additional 50% NOx reduction. Through implementation of LNBs, the Pilot Peak Kilns show an average emission rate of 1.59 lbs of NOx / ton of lime compared to the Nelson Kilns 1 and 2 pre-control average of 6.4 lbs of NOx / ton of lime. The Nelson Kilns generated NOx emissions are 4 times greater than the current LNB emissions in Pilot Peak. Based on the significantly reduced gas stream NOx concentrations at Pilot Peak, the SNCR additive removal efficiency would decay making this control less effective. For kilns where LNB technology has already been applied, it is likely that any additive removal efficiency benefit would be marginal at best.

In the correspondence above, NDEP suggests that a vendor guarantee might be used to validate Graymont's assertion that 50% NOx reduction is unreasonable. Graymont did not request a vendor guarantee for the Class 4 engineering cost estimate we received from our vendors. NDEP is cautioned that vendor guarantees would be premature at the level of a Class 4 engineering estimate as additional design and initial feasibility testing would be required to begin to make any estimate about the viability, regardless of the efficiency, of such a novel abatement system. Graymont's vendors are not, at the present time, in any position to make guarantees about removal efficiency at the current conceptual stage of this project.

Moreover, and elaborated upon below, ammonia slip from an SNCR application would result in an unintended, but material, increase in condensable particulate emissions in the form of ammonium nitrate, ammonium sulfate and ammonium chloride salts. In this manner, a well-intended abatement project would almost certainly result in cost prohibitive, low value installations resulting in impact(s) that are counterproductive to NDEP's stated RH program goals.

In summary, Graymont would be naive to characterize the potential for SNCR NOx reduction at Pilot Peak beyond 20% because the removal efficiency of the system cannot be estimated or derived. Any vendor guarantee on the removal efficiency of a conceptual system is premature and would mean little at this time, even if a vendor were willing to provide one. Moreover, achieving additive control over and above LNB control with emission intensities four times less than LNA's Nelson Plant ensures that removal efficiencies beyond the removal realized by LNB will be marginal at best.

Graymont's Q/d Screening Threshold was Calculated Incorrectly

Nevada and many other states use a Q/d screening calculation to determine which sources may impact visibility in class I areas and thereby should undergo the four-factor test. This Q/d calculation is a surrogate, quantitative metric that is correlated to some degree with visibility impacts as they would be estimated via air quality modeling. Although simple, Q/d is a widely accepted and used surrogate for a source's visibility impacts. It does not account for transport direction or geography which are important factors here since Pilot Peak is downwind from the Jarbidge Class I Area.

Based on NDEP's assessment, the Graymont Q/d threshold was only slightly greater than the threshold used to determine which sources would be included in this Round 2 regional haze analysis. However, in the case of Nevada, NDEP selected a screening Q/d ratio of only 5, whereas most other states use a ratio of 10. This was intentional as NDEP recognized that unless the screening threshold were cut in half to 5, the Pilot Peak facility would be excluded from its analysis.[7] Consistent with how NDEP designed it Q/d screen, it calculated a Q/d ratio for Pilot Peak of 5.15.

However, despite these efforts, Pilot Peak still does not meet the conservative Q/d threshold of 5 – its emissions are just too low and it is too far from Jarbidge. It appears that the emission intensity (Q) reported by Graymont to NDEP and the Q from the 2014 National Emission Inventory differ by 52 tons of combined NOx, SOX and PM. Graymont cannot speculate on how an additional 52 tons were added to the NEI. Graymont can, however, attest to the accuracy of the 2014 Air Emission Inventory as reported to NDEP for reporting year 2014.

Based on the 2014 emission inventory submitted to NDEP, the Pilot Peak facility has a 2014 Q/d ratio of 4.6 (621 tpy NO_X, SO_X, and PM / 131 km) rather than 5.15 calculated by NDEP based on the 2014 NEI. [8] This correction results in Graymont's Pilot Peak facility falling below the threshold for inclusion in this Round 2 regional haze analysis. Graymont's Pilot Peak facility simply does not reach NDEP's Q/d threshold of 5. The Q/d screening threshold further supports a finding that any visibility impact by Pilot Peak is inconsequential and the facility should be excluded from this round of analysis.

Pilot Peak does not meaningfully Impact Visibility at Jarbidge Wilderness Area

[7] October 6, 2020 RH Stakeholder Meeting ("…if we set [the Q/d threshold] at 10, it would cause some of these to drop off").

[8] Graymont reported 621 tons of combined emissions of NO_X, SO_X, and PM in the 2014 annual emission inventory, which does not match emission in the 2014 National Emission Inventory (NEI), which reported a value 52 tons higher. Please see Appendix B for to review a copy of Graymont's Pilot Peak 2014 Emission Inventory.

Beyond the conclusion from the simplified Q/d screening approach, two other more detailed pieces of information also demonstrate that Graymont's kilns do not meaningfully contribute to visibility impairment at the Jarbidge Wilderness Area:

- Analysis of wind data from nearby weather stations and terrain indicate it is extremely unlikely for emissions from Pilot Peak to travel to Jarbidge, and
- Analysis of pollutants causing visibility impairment at Jarbidge clearly shows that NO_X emissions do not cause or contribute to visibility impairment.

As mentioned, the Q/d analysis is a surrogate of the potential for Pilot Peak air emissions to impact Jarbidge visibility. Q/d does not consider transport or geography.

However, wind roses obtained from monitoring stations located near both the Graymont Pilot Peak facility and the Jarbidge Wilderness Area indicate that emissions from the Pilot Peak kilns are extremely unlikely to travel to the Jarbidge Wilderness area. Data from the Wild Horse Reservoir station, located just west of the Jarbidge Wilderness area, indicates that winds travel primarily north and south in that area, with less than two percent of wind coming from the southeast (the direction of the Pilot Peak plant).

While wind data from the Wendover US Air Force base, located nearer to the Pilot Peak facility, shows a somewhat higher fraction of winds traveling from the southeast, the topography of the region suggests that it would be extremely unlikely for conditions to allow emissions from Pilot Peak to travel to the Jarbidge Wilderness area. Several mountain ranges run north-south between the facility and the Jarbidge Wilderness area, which are likely to divert any winds that would otherwise have the potential to carry emissions to the Class I area. In cases when north-south mountain ranges would not divert the flow, the wind from the southeast would also dominate over a north-south wind near Jarbidge diverting the plume. A map of the region with wind rose overlays is provided in Figure 1, below.

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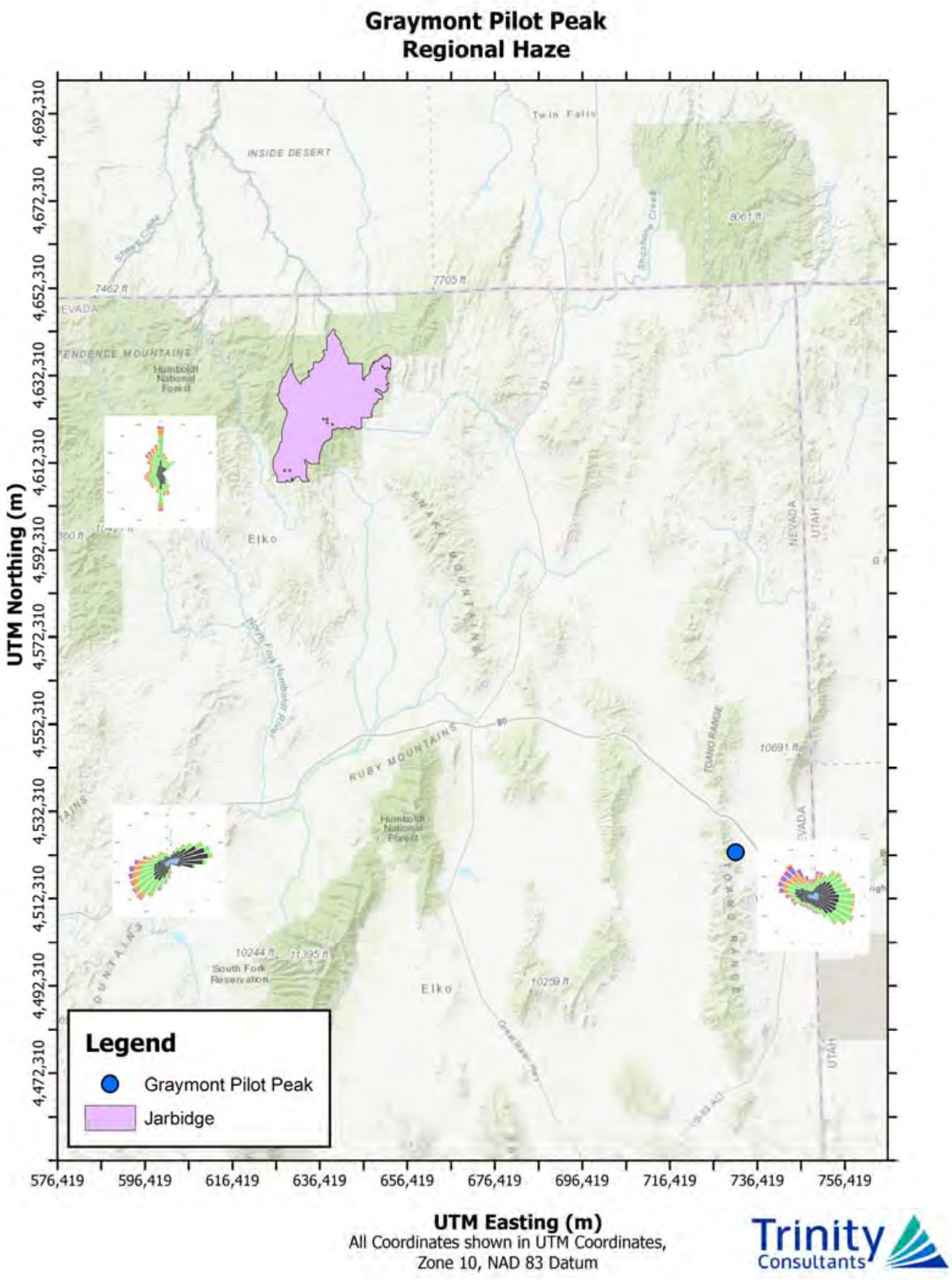

Figure 1. Map of Pilot Peak, Jarbidge Wilderness Area, and Nearby Wind Rose Data

NOx has nearly zero impact on regional haze at Jarbidge Wilderness Area

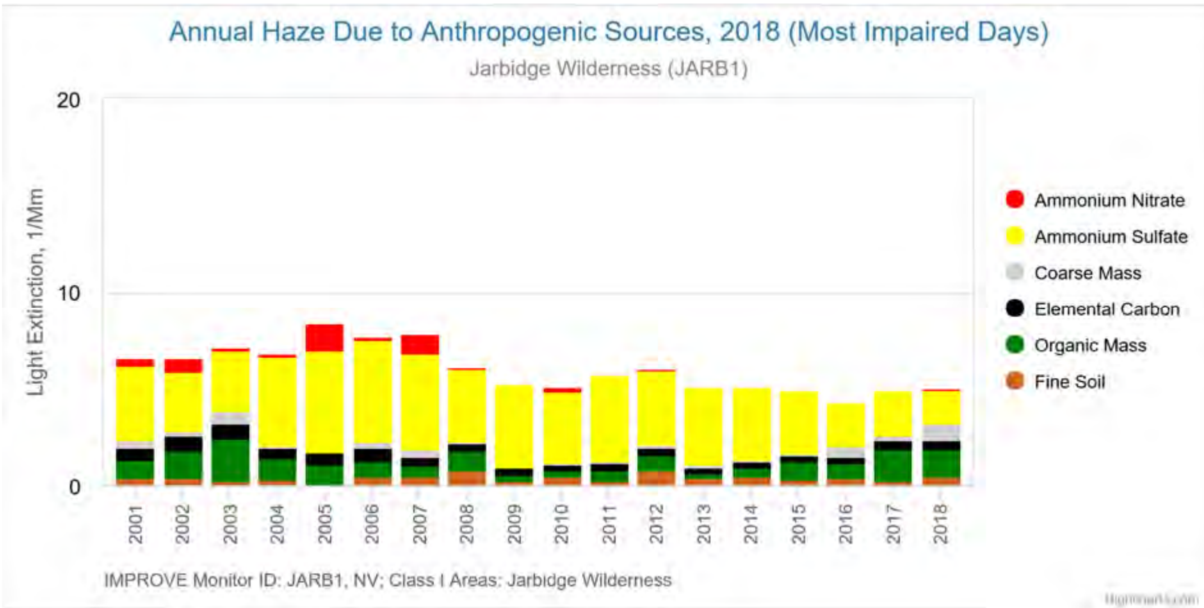

Figure 2. Anthropogenic Contributions to Regional Haze at the Jarbidge Wilderness Area

Figure 2 above shows the anthropogenic pollutants[9] that contribute to visibility improvement from 2001 to 2018. As illustrated in the figure, nitrate (the only visibility impairing pollutant that may be formed from NO_X) contributes essentially zero to impairment at Jarbidge. Therefore, it is not physically possible that reducing NO_X emissions from Graymont's Pilot Peak plant could improve visibility at Jarbidge and should not be considered as part of the regional haze program.

SNCR Technology for Rotary Lime Kilns is not Unconditionally Commercially Available to Graymont

Based upon available information, it appears that the SNCR technology identified by NDEP for evaluation is proprietary to LNA. Graymont conducted a patent search to identify intellectual property owned by LNA and directed toward SNCR on preheater lime kilns. Graymont identified LNA Patent 7,377,773: "Method of Reducing NO_X

[9] EPA's 2017 RHR Revision rules focus on making visibility improvements on the days with the most anthropogenic visibility impairment, as opposed to the days with the most visibility impairment overall. See, 86 Fed. Reg. 19793, 19795 (April 15, 2021).

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Emissions in Rotary Preheater Mineral Kilns" from May 27, 2008. While Graymont has not investigated the validity of the patent, nor does Graymont concede the patentability of the SNCR technology, it is likely that the SNCR technology employed by LNA, specifically directed toward preheater lime kilns, is protected by a patent. The reader is directed to Appendix C wherein a discussion of LNA's SNCR patent can be reviewed.

This is consistent with conclusions made by the Illinois Environmental Protection Agency (Illinois EPA) in the Responsiveness Summary for the PSD permit application for Mississippi Lime company in 2015, where the Illinois EPA noted "Lhoist continues to note that the SNCR systems for those kilns may incorporate proprietary technology and equipment and will need to be treated as confidential business information by USEPA."[10]

As stated in the four-factor analysis and Graymont's response to comments from the NDEP and the FLMs, 40 CFR Subpart 51 Appendix Y defines availability, a prerequisite for determining whether a technology could be applied for the Regional Haze Rule, stating that "a technology is considered 'available' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term." Inherent in the determination made by the Illinois EPA for PSD-BACT (a program with different and more stringent requirements than the regional haze program) is the conclusion that this technology is not considered unconditionally commercially available.

LNA's existing SNCR patent directed toward preheater lime kilns, if determined to be valid and patentable, could have material implications for Graymont's attached cost analysis. Graymont's current cost analysis does not make any attempt to reconcile potential intellectual property costs that might be associated with a patent license or any royalty payment structure. Were Graymont to make some assessment of those potential costs, the already infeasible costs associated with SNCR at Pilot Peak would become even more untenable for installation.

Instead of making any attempt to represent what additional costs for intellectual property might look like beyond the costs represented in the cost analysis, Graymont instead provides NDEP with the following disclaimers:

---

[10] Illinois Environmental Protection Agency Bureau of Air, "Responsiveness Summary for the Public Comment Period on the Issuance of A Construction Permit/PSD Approval for Mississippi Lime Company to Construct a Lime Plant in Prairie du Rocher, Illinois," Page 23. (September 2015). http://www.epa.state.il.us/public-notices/2014/mississippi-lime/responsiveness-summary.pdf

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- Graymont has not investigated the validity of LNA's '773 Patent, nor do we concede the patentability of the LNA SNCR technology,

- It is our belief that LNA will defend its exclusive patent rights if the LNA SNCR technology is implemented by Graymont or at a minimum expect Graymont to take a license to the '773 Patent in order to implement the technology,

- Graymont notes here that project capital and operational costs represented in this letter and its attachments do not attempt to account for any licensing fees or royalties that might apply to this analysis and so estimated costs could be substantially higher than estimated in this letter and its attachments.

As NDEP ponders its Regional Haze SIP, the agency is encouraged to consider that the implications of LNA's intellectual property holdings as they relate to Nevada's Regional Haze initiative are not fully understood at this time by Graymont.

Updated Cost Calculations and Vendor Estimate

On January 28, 2021, NDEP provided Graymont with a letter requesting additional information. In addition to requesting Pilot Peak kiln residence time and temperature, the agency requested detailed cost information for installation of SNCR technology. From NDEP's January 28, 2021 letter:

> *"In Lhoist North America's latest 4-factor analysis for their Apex Plant, they assume a total capital cost of implementing SNCR at about $500,000 regardless of differing parameters among the kilns. This estimate was also used in the Nelson Facility's 5-factor analysis and references Lhoist's prior experience in implementing SNCR at another facility. As mentioned above, the Control Cost Manual's spreadsheet for SNCR is heavily based on empirical data from fossil-fuel-fired boilers. This populates a total capital cost for SNCR that is an order of magnitude larger than what was actually reported from successful implementation of SNCR on lime kilns. NDEP strongly suggests obtaining a vendor quote to avoid this calculation error."*[11]

Pursuant to NDEP's request, Graymont performed a Class 4 engineering cost analysis to determine capital and operating cost estimates for installation of SNCR control at Pilot Peak. The Class 4 results are provided in Table 2:

[11] Graymont Pilot peak 4-Factor Analysis Request, Letter, Nevada Division of Environmental Protection, January 28, 2021.

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Table 2: Summary of Pilot Peak SNCR Costs[12]

Kiln	Total Capital Investment	Annual Operating Cost	Total Annual Cost[13]	Tons NOx in	Tons NOx Reduced[14]	Cost Effectiveness ($/ton of NOx removed)
1	$1,734,147			135.3	27.1	
2	$1,219,080			173.1	34.6	
3	$1,219,080			206.9	41.4	
Total	**$4,172,307**	**$3,775,976**	**$4,103,713**	515.3	103.1	**$39,803**

Graymont notes here the apparent disparity between our third-party Class 4 engineering cost estimate and LNA's 4-factor analysis for their Apex plant. In both the Apex 4-factor analysis and their Nelson Plant five factor analysis, LNA asserted a round capital cost estimate of $500,000 capital investment per kiln.

Graymont cannot speculate on how LNA's cost estimates were so similar, regardless of differing parameters among the kilns. Nor can we speculate on the disparity of cost displayed between LNA's estimate and Graymont's Class 4 engineering estimate. Graymont can only attest that the Class 4 estimate was performed by an independent third party with a sound engineering approach.

Note that Graymont's cost estimate makes no attempt to reconcile any potential intellectual property costs that might be required in the event that Graymont were forced to pursue licensing or royalty fees.

The Technical Feasibility of SNCR on Preheater Lime Kilns is a Novel Technology Not Proven in Broad Application

Lime kilns vary considerably in design, so implementation at two facilities does not indicate feasibility for all lime kilns. Particularly in the case of technologies that are not widely used in an industry, where the emission unit in question is as site-specific and unit-specific in its operating parameters and methods as a lime kiln, technical feasibility must be assessed on a unit-by-unit basis. Each kiln has its own design and operating conditions, with variables like temperature, residence time, and physical

[12] Class 4 engineering cost estimates are detailed in Appendix D.
[13] Total Annual Cost = Annual Operating Cost + Annual cost of capital investment at 4.75% for 20 years
[14] Tons NOx reduced based upon 20% control efficiency.

configuration playing a major role in whether a control technology retrofit is possible and what level of emissions control is achievable.

Graymont has reviewed the design characteristics specific to the kilns installed at the Pilot Peak facility to determine the temperature and residence time of kiln gas in the transfer chute in order to answer NDEP's request for additional information. The models indicated an average temperature of 1,821 °F and a maximum of 1,938 °F. For residence time, the models indicated that the average residence time of gases in the transfer chute is 0.5 seconds (maximum of 0.6 seconds). Please see Appendix E to review Graymont's temperature and residence time calculations. The EPA Air Pollution Control Cost Manual (CCM) cites an ideal temperature range of 1,550 °F to 1,950 °F.

The CCM also states that a residence time of 1 second is required for sources to be considered well-suited for SNCR. With a residence time of half the recommended minimum value provided by the EPA, the concerns expressed in Graymont's four-factor analysis regarding the ability of an SNCR ammonia injection system to achieve sufficient mixing for the conversion of NO_X emissions are substantiated. The short residence time, in conjunction with the high dust loading in the transfer chute, pose substantial technical concerns for the feasibility of SNCR as a NO_X control technology.

SNCR Addition at Pilot Peak would have Unintended Negative Repercussions and Generate Condensable Particulate

Even if Pilot Peak emissions could affect Jarbidge, NDEP must also consider the energy and environmental impacts of SCNR and has the flexibility to consider visibility benefits.[15] On this point, condensable particulate emissions from lime kilns occurs when cations and anion species react in the kiln system to create condensable particulate salts. Kiln exhausts are cation-limited as ample anion species are available to form salts. Sulfates, nitrates, and chloride species are present in lime kiln exhaust but do no form condensable particulate species at levels that create non-compliance with condensable particulate emission limits due typically to the relative stochiometric unavailability of a candidate cation species.

[15] See, *e.g.,* Responses to Comments on Protection of Visibility: Amendments to Requirements for State Plans; Proposed Rule (81 FR 26942, May 4, 2016), Docket Number EPA–HQ–OAR–2015–0531, U.S. Environmental Protection Agency at 186; August 2019, EPA issued ''Guidance on Regional Haze State Implementation Plans for the Second Implementation Period'' (''2019 Guidance'') at 36–37.

The addition of SNCR in lime kilns requires the addition of ammonia or urea to lime kiln exhausts to control NOx emissions. While addition of reagent in lime kiln exhausts can, in favorable physical configurations with appropriate temperature and residence times, have the effect of abating NOx production, the addition of reagent will also have unintended negative effects. Over-injection of reagent results in ammonia slip, which produces unintended ammonia emissions, but also contributes to the formation of condensable particulate. Reactions with sulfates, chlorides and nitrates that were previously cation-limited are no longer cation-limited and robust salt formation of ammonium sulfate, ammonium chloride and ammonium nitrate are promoted. Even when ammonia slip is limited through monitoring and injectate control, condensable particulate formation will be enhanced in the kiln system.

Generation of additional condensable particulate creates two practical problems relative to this discussion. First, increases of condensable particulate salt formation will have the immediate effect of increasing PM2.5/PM10 emissions from the Pilot Peak Kilns. Condensable particulate emissions from the Pilot Peak Kilns are currently emitted at a rate where Graymont can remain in compliance with PM10 and PM2.5 emission limits. Addition of reagent to the kiln exhaust will remove the cation-limited condition in the kiln exhausts and promote additional condensable salt formation not accounted for in Graymont's current air permit. Graymont anticipates that if SNCR systems are required on Pilot Peak Kilns that the addition of more cation species will require study to characterize condensable salt formation increases and to develop a program to increase the PM10 and PM2.5 emission limits at Pilot Peak.

A second problem envisioned if SNCR were required at Pilot Peak would be post control generated sources of ammonium nitrate, ammonium sulfate and ammonium chloride emissions produced as PM10 emissions. As stated in the earlier section, we believe that Pilot Peak does not contribute to visibility impacts at Jarbidge Wilderness Area (or other Class I areas). Even if we assume contribution of visibility-impairing emissions from Pilot Peak, SNCR would not benefit visibility at the Class I area if NOx reductions would simply be replaced by PM10 emissions.[16] It is noteworthy to recall that condensable particulate emissions cannot be controlled by gas stream filtration. Condensable particulate emissions can only be controlled by limiting the availability of condensable particulate salt-forming species in the kiln system – which means avoiding the installation of SNCR.

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[16] NDEP recognized the potential visibility disbenefits of SNCR in previous BART analyses. See, Revised Nevada Division of Environmental Protection BART Determination Review of NV Energy's Tracy Generating Station Units 1, 2 and 3(revised October 15, 2009); Revised Nevada Division of Environmental Protection BART Determination Review of NV Energy's Fort Churchill Generating Station Units 1 and 2 (revised October 15, 2009).

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Another environmental impact associated with retrofitting SNCR on the Pilot Peak facility would be the addition of ammonia or urea storage and handling systems. Anhydrous ammonia and aqueous ammonia above 20 percent are considered dangerous to human health. SNCR also creates potential safety hazards associated with the transportation of anhydrous ammonia.[17]

If you have any questions or comments about the information presented in this letter, please do not hesitate to call me at 814.353.2106 or Nate Stettler at 801.716-2621.

Sincerely,

John A. Maitland
US Manager, Health, Safety and Environment

Attachments

cc: Sigurd Jaunarajs, NDEP
Terry McIntyre, Graymont
Hal Lee, Graymont
Nate Stettler, Graymont
Todd Palmer, Michael Best

[17] NDEP recognized the potential for ammonia releases in previous BART analyses. *Supra*, fn. 21.

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Appendix A

Pilot Peak SNCR Cost Effectiveness Calculations

Cost Estimate

Total Capital Investment (TCI)*

SNCR Capital Costs ($SNCR_{cost}$)	
Kiln 1	$1,734,147
Kiln 2	$1,219,080
Kiln 3	$1,219,080
Total SNCR Capital Costs ($SNCR_{cost}$) =	$4,172,307

*Based on class 4 engineering cost estimate

Annual Costs*

Total Annual Cost (TAC)	
TAC = Direct Annual Costs + Indirect Annual Costs	
Kiln 1, Kiln 2, Kiln 3 Combined	$4,103,713

Direct Annual Costs (DAC)	
Kiln 1, Kiln 2, Kiln 3 Combined	$3,775,976

Indirect Annual Cost (IDAC)	
IDAC = Capital Recovery Costs	
Capital Recovery Costs (CR) = (CRF x TCI)	$327,737

CRF = $(i\ (1+ i)^n/(1+ i)^n - 1)$	0.0786
i =	4.75%
n (years) =	20

*Based on lass 4 engineering cost estimate

Cost Effectiveness*

Cost Effectiveness = Total Annual Cost/ NOx Removed/year		
Cost Effectiveness =	$39,803	per ton of NOx removed

Total Annual Cost (TAC) =	$4,103,713

Kiln 1	27.1	tons/year
Kiln 2	34.6	tons/year
Kiln 3	41.4	tons/year
Total NOx Removed (Kiln 1, Kiln 2, Kiln 3)	103.1	tons/year

*tons of Nox reduced based on 20% control efficiency

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Appendix B

Graymont Pilot Peak 2014 Annual Emission Inventory

GRAYMONT

February 25, 2015

Mr. Patrick Anderson
Staff Engineer
Nevada Division of Environmental Protection
Bureau of Air Pollution Control
901 S. Stewart Street, Suite 4001
Carson City, NV 89701

Dear Mr. Anderson:

RE: 2014 Actual Production/Emissions Reporting Form for Graymont Western US Inc. Pilot Peak Facility (Facility ID #A0367)

Enclosed is the 2014 Actual Production/Emissions Reporting Form completed for the Graymont Western US Inc. (Graymont) Pilot Peak Facility. The spreadsheet used was provided by Jasmine Mehta to Graymont's attorney, Denise Kennedy, in March of 2014.

Please note that in both forms provided by NDEP (March-2014 spreadsheet and January 2015 hardcopy) the emission factor for System Sequence #31, System 24-Baghouse D-89 had been updated to reflect the changes in OPTC #AP3274-3447, issued on November 24, 2014. However, as is shown on the attached 2014 Actual Production/Emissions Reporting Form for that OPTC, construction has not yet occurred. Therefore, the throughputs for the proposed modifications are zero and the more efficient baghouse emission factors are not yet applicable. Graymont requests that the emission factors for D-89 revert back to those shown in the 2013 Actual Production/Emissions Reporting Form until the modified unit is operating.

Feel free to call me at (775) 483-5007 if you have any questions. Alternately, you may contact Samantha Heusser, Graymont Environmental Engineer, at (801) 716-2650.

Based on information and belief formed after reasonable inquiry, the statements made in this document are true, accurate and complete.

Sincerely,

Terry McIntyre
Plant Manager
Graymont

Attachments

P.O. Box 2520
Wendover, NV 89883
USA

Nevada Division of Environmental Protection - Bureau of Air Pollution Control
Calender Year 2014 Kiln Emissions based on Stack Testing

Company:	GRAYMONT WESTERN US, INC	**Class Type:**	1B-PSD	**Contact:**	TERRY MCINTYRE, PILOT PEAK PLANT MANAGER
Address:	3950 SOUTH 700 EAST SUITE 301, SALT LAKE CITY, UT 84107				
Permit #:	**AP50321439.01**	**Facility:**	PILOT PEAK		Date Below Valid as of: 1/30/2015

In accordance with Permit Conditions VI.J.4.b.ix, VI.M.4.b.ix, and VI.Q.4.b.ix, Graymont is providing the following annual emissions and emission factors in units of lbs/ton of lime produced for Kiln #1, Kiln #2, and Kiln #3 Circuits. The emissions are based on the emission factors that were derived from the stack testing performed on August 25-29, 2014.

Kiln Circuit	Lime Production Rates	
	2014 Actual	Units
K1	125,313	tons/yr
K2	199,362	tons/yr
K3	287,132	tons/yr

Pollutant ID	2014 Emission Factors (lbs/ton-lime production)			Annual Emissions (tons/year)			
	K1 Circuit	K2 Circuit	K3 Circuit	K1 Circuit	K2 Circuit	K3 Circuit	Total
PM	0.160	0.233	0.091	10.04	23.27	13.11	46.42
PM_{10}	0.231	0.289	0.041	14.44	28.77	5.90	49.12
NO_x	2.102	1.302	1.374	131.69	129.78	197.32	458.79
CO	0.111	0.104	0.123	6.93	10.36	17.67	34.95
VOC*	0.007	0.027	0.005	0.42	2.72	0.72	3.86
SO_2	Emissions based on data recorded by the SO_2 CEMS CDCS.			3.34	5.59	14.01	22.94

*VOC calculation uses a 2012 emission factor because the 2013 stack test emissions for VOC were non-detectable (ND)

Example Emission calculations:
Annual Emissions [tons/year] = Emission factor x 2013 Actual Lime Production Rate / (2000 lb/ton)

Data Prepared By:

Print Name: Shane Morley

I hereby certify that the above information is true and accurate under penalty of perjury:

Signed:

Print Name: Terry McIntyre

Title: Plant Manager - Pilot Peak Plant
Responsible Official

Nevada Division of Environmental Protection - Bureau of Air Pollution Control
Calendar Year 2014 HAPS Inventory

Company:	GRAYMONT WESTERN US, IN	**Class Type:**	1B-PSD	**Contact:**	TERRY MCINTYRE, PILOT PEAK PLANT MANAGER
Address:	3950 SOUTH 700 EAST SUITE 301, SALT LAKE CITY, UT 84107				
Permit #:	**AP50321439.01**	**Facility:**	PILOT PEAK		Data Below Valid as of: 1/30/2015

In accordance with Permit Condition VII.A.2.a, Graymont is providing the following HAP emissions inventory spreadsheet. Emission factors were obtained from previously submitted emission inventories. The combustion of coal in the three kilns is the only source of HAP emissions at the Pilot Peak Plant.

Kiln Circuit	Lime Production Rates 2014 Actual	Max Allowable	Units	HCl (7782-50-5) Emission Factor	
K1	125,313	219,000	tons/yr	0.0101	lbs/ton
K2	199,362	291,708	tons/yr	0.0127	lbs/ton
K3	287,132	438,000	tons/yr	0.00753	lbs/ton

Pollutant ID	Emission Factor	Emission Factor Units	Annual HAP Emissions (tons/year) K1 Actual	K2 Actual	K3 Actual	Actual Total (All 3 kilns)	Max Potential (All 3 kilns)	Notes
100-41-4	0.000972	lbs/ton	0.061	0.097	0.140	0.297	0.461	Nevada Factors - Production Rate
106-42-3	0.00202	lbs/ton	0.127	0.201	0.290	0.618	0.958	Nevada Factors - Production Rate
108-38-3	0.00202	lbs/ton	0.127	0.201	0.290	0.618	0.958	Nevada Factors - Production Rate
108-88-3	0.001776	lbs/ton	0.111	0.177	0.255	0.543	0.842	Nevada Factors - Production Rate
110-54-3	0.00404	lbs/ton	0.253	0.403	0.580	1.236	1.916	Nevada Permit #AP3274-0261 - Emission Rate
50-00-0	0.01822	lbs/ton	1.142	1.816	2.616	5.574	8.643	Nevada Factors - Production Rate
71-43-2	0.001656	lbs/ton	0.104	0.165	0.238	0.507	0.786	Nevada Factors - Production Rate
7782-50-5	See above	lbs/ton	0.633	1.266	1.081	2.980	4.607	HCl Stack Test Results- Production Rate
95-47-6	0.000444	lbs/ton	0.028	0.044	0.064	0.136	0.211	Nevada Factors - Production Rate
CADMIUM	0.000112	lbs/ton	0.007	0.011	0.016	0.034	0.053	Nevada Factors - Production Rate
CHROMIUM	0.002408	lbs/ton	0.151	0.240	0.346	0.737	1.142	Nevada Factors - Production Rate
COBALT	0.002296	lbs/ton	0.144	0.229	0.330	0.702	1.089	Nevada Factors - Production Rate
LEAD	1.15E-06	lbs/ton	0.000	0.000	0.000	0.000	0.001	National Lime Association factor.
Mn	0.00094	lbs/ton	0.059	0.094	0.135	0.288	0.446	Nevada Factors - Production Rate
NICKEL	0.0008	lbs/ton	0.050	0.080	0.115	0.245	0.379	Nevada Factors - Production Rate
SELENIUM	0.0008	lbs/ton	0.050	0.080	0.115	0.245	0.379	Nevada Factors - Production Rate
					TOTAL EMISSIONS FOR ALL HAPS:	**14.76**	**22.87**	
					HIGHEST EMISSIONS FOR A SINGLE HAP:	**5.57**	**8.64**	(50-00-0 Formaldehyde)

Example Emission calculations:

Actual for individual kilns: Actual Emissions [tons/year] = Emission factor x 2012 Actual Lime Production / (2000 lb/ton)

Actual for all kilns: Actual Total Emissions [tons/year] = K1 Actual Emissions + K2 Actual Emissions + K3 Actual Emissions

Max Potential for all kilns: Max Potential Emissions [tons/year] = Sum of Max Allowable Lime Production Rates x Emission Factor / (2000 lb/ton)

Data Prepared By
Print Name: Shane Morley

I hereby certify that the above information is true and accurate under penalty of perjury:

Signed:

Print Name: Terry McIntyre

Title: Plant Manager - Pilot Peak Plant

Responsible Official

Nevada Division of Environmental Protection - Bureau of Air Pollution Control
Calendar Year 2014 Actual Production/Emissions Reporting Form

Company: GRAYMONT WESTERN US, INC
Class Type: 1B-PSD
Address: 3950 SOUTH 700 EAST SUITE 301, SALT LAKE CITY, UT 84107
Contact: TERRY MCINTYRE, PILOT PEAK PLANT MANAGER
Permit #: AP32741329.01
Facility: PILOT PEAK
Data Below Valid as of: 1/30/2015

System Seq#: 1
Description: SYSTEM F1 - LIMESTONE QUARRY DRILLING & BLASTING
Notes: Fugitive Emissions (F0.001 - F0.003)

Control #: 1
Description: GOOD OPERATING PRACTICES
Comments: Fugitive Emissions (F0.001 - F0.003)

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	228,951	tons/yr	11.853	LB/HR		N/A	
PM10	228,951	tons/yr	4.149	LB/HR		N/A	

System Seq#: 2
Description: SYSTEM 01 - LIMESTONE TRUCK DUMP
Notes: PF1.001

Control #: 1
Description: WET SUPRESSION SYSTEM
Comments: PF1.001

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	1,726,619	tons/yr	0.00219	LB/TON	1.891	2842	
PM10	1,726,619	tons/yr	0.00077	LB/TON	0.665	2842	

Form must be signed by a Responsible Official or his designee, approved by the Director, pursuant to NAC 445B.156.
Make any changes necessary to the above data. justify any changes by placing comments in the Notes column describing the changes.

System Seq#: 3

Description: SYSTEM 02 - PRIMARY CRUSHING AND SCREENING CIRCUIT (D-1)
Notes: S2.001 - S2.010.2

Control #: 1

Description: BAGHOUSE D-1
Comments: S2.001 - S2.010.2: Flow = dscf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	1,726,619	tons/yr	4.11	LB/HR	5.840	2842	
PM10	1,726,619	tons/yr	3.29	LB/HR	4.675	2842	

System Seq#: 4

Description: SYSTEM 03 - SECONDARY SCREENING CIRCUIT (D-311)
Notes: S2.011 - S2.015

Control #: 1

Description: BAGHOUSE D-311
Comments: S2.011 - S2.015: Flow = dscf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	2,685,766	tons/yr	2.06	LB/HR	2.927	2842	
PM10	2,685,766	tons/yr	1.65	LB/HR	2.345	2842	

Form must be signed by a Responsible Official or his designee, approved by the Director, pursuant to NAC 445B.156.
Make any changes necessary to the above data. justify any changes by placing comments in the Notes column describing the changes.

System Seq#: 5

Description: SYSTEM 04 - SECONDARY LIMESTONE CRUSHING CIRCUIT (D-2)
Notes: S2.210 - S2.223 The emissions of S2.222 & S2.223 are capped by System 004.

Control #: 1

Description: BAGHOUSE D-2
Comments: S2.210 - S2.221: Flow = 10,000 dscf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	0	tons/yr	1.71	LB/HR	0.000	0	New system added to permit 11/9/04;
PM10	0	tons/yr	1.37	LB/HR	0.000	0	Not installed at this time.

Control #: 2

Description: BAGHOUSE D-311
Comments: S2.222 & S2.223: Flow = 12,000 dscf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	0	tons/yr	2.06	LB/HR	0.00	0	D-311 serves the secondary screen, emissions counted above.
PM10	0	tons/yr	1.65	LB/HR	0.00	0	

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System Seq#: 6 **Description:** SYSTEM 05 - LIMESTONE QUARRY CONVEYANCE TRANSFERS
Notes: PF1.002 - PF1.007

Control #: 1 **Description:** WATER SPRAYS W/ CHEMICAL SURFACTANT
Comments: PF1.002 & PF1.003, PF1.005, PF1.007

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	1,342,393	tons/yr	0.002	LB/TON	1.342	6438	
PM10	1,342,393	tons/yr	0.00072	LB/TON	0.483	6438	

Control #: 2 **Description:** WATER SPRAYS W/ CHEMICAL SURFACTANT
Comments: PF1.004 & PF1.006

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	1,342,393	tons/yr	0.001	LB/TON	0.671	6438	
PM10	1,342,393	tons/yr	0.00036	LB/TON	0.242	6438	

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System Seq#: 7 **Description:** SYSTEM 06 - LIME PLANT CONVEYANCE TRANSFERS
Notes: PF1.008 - PF1.026

Control #: 1 **Description:** UNDERGROUND TRANSFERS
Comments: PF1.008 - PF1.023 & PF1.026

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	1,348,016	tons/yr	0.0140845	LB/TON	9.493	7643	
PM10	1,348,016	tons/yr	0.006664	LB/TON	4.492	7643	

Control #: 2 **Description:** BEST OPERATING PRACTICES
Comments: PF1.024

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	1,348,016	tons/yr	0.001657	LB/TON	1.117	7643	
PM10	1,348,016	tons/yr	0.000784	LB/TON	0.528	7643	

Control #: 3 **Description:** BEST OPERATING PRACTICES
Comments: PF1.025

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	1,348,016	tons/yr	0.001657	LB/TON	1.117	7643	
PM10	1,348,016	tons/yr	0.000784	LB/TON	0.528	7643	

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System Seq#: 8 **Description:** SYSTEM F2 - LIMESTONE QUARRY CONVEYANCE WIND EROSION
Notes: Fugitive Emissions (F0.004 - F0.019)

Control #: 1 **Description:** GOOD OPERATING PRACTICES
Comments: Fugitive Emissions (F0.004 - F0.019)

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	1,348,016	tons/yr	1.867	LB/HR		N/A	
PM10	1,348,016	tons/yr	0.686	LB/HR		N/A	

System Seq#: 9 **Description:** SYSTEM 07 - LIME PLANT STONE DRESSING SCREENS (KILNS 1 & 2)
Notes: S2.016 - S2.019

Control #: 1 **Description:** BAGHOUSE D-10
Comments: S2.016 - S2.019: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	725,457	tons/yr	0.86	LB/HR	2.939	6836	
PM10	725,457	tons/yr	0.69	LB/HR	2.358	6836	

System Seq#: 10 **Description:** SYSTEM 08 - LIME PLANT STONE DRESSING SCREEN (KILN 3)
Notes: S2.020 - S2.023

Control #: 1 **Description:** BAGHOUSE D-317
Comments: S2.020 - S2.023: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	622,559	tons/yr	1.46	LB/HR	4.700	6438	
PM10	622,559	tons/yr	1.17	LB/HR	3.766	6438	

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System Seq#: 11 **Description:** SYSTEM F3 - LIME PLANT WIND EROSION
Notes: Fugitive Emissions (F0.020 - F0.029)

Control #: 1 **Description:** GOOD OPERATING PRACTICES
Comments: Fugitive Emissions (F0.020 - F0.029)

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	1,348,016	tons/yr	3.482	LB/HR		N/A	
PM10	1,348,016	tons/yr	1.287	LB/HR		N/A	

System Seq#: 12 **Description:** SYSTEM 09 - LIME PLANT STONE SURGE BIN N-19 & N-219 (KILNS 1 & 2)
Notes: S2.024 - S2.030

Control #: 1 **Description:** BAGHOUSE D-19
Comments: S2.024 - S2.030.: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	725,457	tons/yr	0.77	LB/HR	2.708	7033	
PM10	725,457	tons/yr	0.62	LB/HR	2.180	7033	

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System Seq#: 13 **Description:** SYSTEM 10 - KILN 1 CIRCUIT (D-85)

Notes: S2.031 - S2.033

Control #: 1 **Description:** BAGHOUSE D-85

Comments: S2.031 - S2.033: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
CO	125,313	tons/yr	0.111	LB/TON	6.93	7033	EF is based on 8/26-27/14 stack test data
NOX	125,313	tons/yr	2.102	LB/TON	131.69	7033	EF is based on 8/26-27/14 stack test data
PM	125,313	tons/yr	0.160	LB/TON	10.04	7033	EF is based on 8/26-27/14 stack test data
PM	125,313	tons/yr	0.160	LB/TON	10.04	7033	EF is based on 8/26-27/14 stack test data
PM10	125,313	tons/yr	0.231	LB/TON	14.44	7033	EF is based on 8/26-27/14 stack test data
PM10	125,313	tons/yr	0.231	LB/TON	14.44	7033	EF is based on 8/26-27/14 stack test data
S	125,313	tons/yr	NA	NA	1.67	7033	S emiss. are molecular weight ratio (32/64) of SO2 emiss.
SO2	125,313	tons/yr	0.007	NA	3.34	7033	Emissions total as reported from CEMS data.
VOC	125,313	tons/yr	0.007	LB/TON	0.42	7033	EF is based on 8/26-27/14 stack test data

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System Seq#: 14 **Description:** SYSTEM 11 - KILN 1 COAL HANDLING 1 CIRCUIT
Notes: PF1.027 - PF1.030

Control #: 1 **Description:** GOOD OPERATING PRACTICES
Comments: PF1.027 & PF1.028

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	24,365	tons/yr	0.001	LB/TON	0.012	7033	
PM10	24,365	tons/yr	0.0004	LB/TON	0.005	7033	

Control #: 2 **Description:** ENCLOSED BUILDING
Comments: PF1.029 & PF1.030

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	24,365	tons/yr	0.00008	LB/TON	0.001	7033	
PM10	24,365	tons/yr	0.00004	LB/TON	0.000	7033	

System Seq#: 15 **Description:** SYSTEM 12 - KILN 1 COAL SILO T-90 (D-91)
Notes: S2.034 & S2.035

Control #: 1 **Description:** BAGHOUSE D-91
Comments: S2.034 & S2.035: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	24,365	tons/yr	0.17	LB/HR	0.598	7033	
PM10	24,365	tons/yr	0.14	LB/HR	0.492	7033	

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System Seq#: 16 **Description:** SYSTEM F4 - KILN 1 COAL HANDLING WIND EROSION
Notes: Fugitive Emissions (F0.030 & F0.031)

Control #: 1 **Description:** GOOD OPERATING PRACTICES
Comments: Fugitive Emissions (F0.030 & F0.031)

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	24,365	tons/yr	0.062	LB/HR		N/A	
PM10	24,365	tons/yr	0.023	LB/HR		N/A	

System Seq#: 17 **Description:** SYSTEM 13 - KILN 2 CIRCUIT (D-285)
Notes: S2.036 - S2.038

Control #: 1 **Description:** BAGHOUSE D-285
Comments: S2.036 - S2.038: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
CO	199,362	tons/yr	0.104	LB/TON	10.36	7033	EF is based on 8/28/14 stack test data
NOX	199,362	tons/yr	1.302	LB/TON	129.78	7033	EF is based on 8/28/14 stack test data
PM	199,362	tons/yr	0.233	LB/TON	23.27	7033	EF is based on 8/28/14 stack test data
PM	199,362	tons/yr	0.233	LB/TON	23.27	7033	EF is based on 8/28/14 stack test data
PM10	199,362	tons/yr	0.289	LB/TON	28.77	7033	EF is based on 8/28/14 stack test data
PM10	199,362	tons/yr	0.289	LB/TON	28.77	7033	EF is based on 8/28/14 stack test data
S	199,362	tons/yr	0.001	NA	2.80	7033	S emiss. are molecular weight ratio (32/64) of SO2 emiss.
SO2	199,362	tons/yr	0.001	NA	5.59	7033	Emissions total as reported from CEMS data.
VOC	199,362	tons/yr	0.027	LB/TON	2.72	7033	EF is based on 8/28/14 stack test data

System Seq#: 18 **Description:** SYSTEM 13A - KILN 2 CIRCUIT (D-282)
Notes: S2.036.1 - S2.038.1

Control #: 1 **Description:** BAGHOUSE (D-282)
Comments: S2.036.1 - S2.038.1 Note: Stk volume flow rate is dscfm.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	199,362	tons/yr	0.17	LB/HR	0.598	7033	
PM10	199,362	tons/yr	0.14	LB/HR	0.492	7033	

System Seq#: 19 **Description:** SYSTEM 14 - KILN 2 COAL HANDLING CIRCUIT
Notes: PF1.031 - PF1.033

Control #: 1 **Description:** GOOD OPERATING PRACTICES
Comments: PF1.031

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	41,235	tons/yr	0.0005	LB/TON	0.010	7033	
PM10	41,235	tons/yr	0.0002	LB/TON	0.004	7033	

Control #: 2 **Description:** ENCLOSED BUILDING
Comments: PF1.032 & PF1.033

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	41,235	tons/yr	0.0001	LB/TON	0.002	7033	
PM10	41,235	tons/yr	0.00002	LB/TON	0.000	7033	

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System Seq#: 20 **Description:** SYSTEM F5 - KILN 2 COAL HANDLING WIND EROSION
Notes: Fugitive Emissions (F0.032 & - F0.033)

Control #: 1 **Description:** GOOD OPERATING PRACTICES
Comments: Fugitive Emissions (F0.032 & F0.033)

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	41,235	tons/yr	0.029	LB/HR		N/A	
PM10	41,235	tons/yr	0.01	LB/HR		N/A	

System Seq#: 21 **Description:** SYSTEM 15 - KILN 2 COAL SILO T-290 (D-291)
Notes: S2.039 & S2.040

Control #: 1 **Description:** BAGHOUSE D-291
Comments: S2.039 & S2.040: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	41,235	tons/yr	0.17	LB/HR	0.598	7033	
PM10	41,235	tons/yr	0.14	LB/HR	0.492	7033	

System Seq#: 22 **Description:** SYSTEM 16 - LIME PLANT STONE FEED TO KILN 3 (D-382)
Notes: S2.041

Control #: 1 **Description:** BAGHOUSE D-382
Comments: S2.042: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	565,963	tons/yr	0.26	LB/HR	0.930	7153	
PM10	565,963	tons/yr	0.21	LB/HR	0.751	7153	

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System Seq#: 23 **Description:** SYSTEM 17 - KILN 3 CIRCUIT (D-385)
Notes: S2.042 - S2.044

Control #: 1 **Description:** BAGHOUSE D-385
Comments: S2.042 - S2.044: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
CO	287,132	tons/yr	0.123	LB/TON	17.67	7153	EF is based on 8/29/14 stack test data
NOX	287,132	tons/yr	1.374	LB/TON	197.32	7153	EF is based on 8/29/14 stack test data
PM	287,132	tons/yr	0.091	LB/TON	13.11	7153	EF is based on 8/29/14 stack test data
PM	287,132	tons/yr	0.091	LB/TON	13.11	7153	EF is based on 8/29/14 stack test data
PM10	287,132	tons/yr	0.041	LB/TON	5.90	7153	EF is based on 8/29/14 stack test data
PM10	287,132	tons/yr	0.041	LB/TON	5.90	7153	EF is based on 8/29/14 stack test data
S	287,132	tons/yr	0.014	NA	7.01	7153	S emiss. are molecular weight ratio (32/64) of SO2 emiss.
SO2	287,132	tons/yr	0.003	NA	14.01	7153	Emissions total as reported from CEMS data.
VOC	287,132	tons/yr	0.005	LB/TON	0.72	7153	EF is based on 8/29/14 stack test data

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System Seq#: 24 **Description:** SYSTEM 18 - KILN 3 COAL HANDLING CIRCUIT
Notes: PF1.034 - PF1.036

Control #: 1 **Description:** GOOD OPERATING PRACTICES
Comments: PF1.034

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	60,975	tons/yr	0.0005	LB/TON	0.015	7153	
PM10	60,975	tons/yr	0.0002	LB/TON	0.006	7153	

Control #: 2 **Description:** ENCLOSED BUILDING
Comments: PF1.035 & PF1.036

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	60,975	tons/yr	0.00005	LB/TON	0.002	7153	
PM10	60,975	tons/yr	0.00002	LB/TON	0.001	7153	

System Seq#: 25 **Description:** SYSTEM F6 - KILN 3 COAL HANDLING WIND EROSION
Notes: Fugitive Emissions (F0.034 & - F0.035)

Control #: 1 **Description:** GOOD OPERATING PRACTICES
Comments: Fugitive Emissions (F0.034 & F0.035)

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	60,975	tons/yr	0.03	LB/HR		N/A	
PM10	60,975	tons/yr	0.01	LB/HR		N/A	

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System Seq#: 26 **Description:** SYSTEM 19 - KILN 3 COAL SILO T-391 (D-391)
Notes: S2.045 & S2.046

Control #: 1 **Description:** BAGHOUSE D-391
Comments: S2.045 & S2.046: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	60,975	tons/yr	0.17	LB/HR	0.608	7153	
PM10	60,975	tons/yr	0.14	LB/HR	0.501	7153	

System Seq#: 27 **Description:** SYSTEM 20 - PRODUCT LIME LOADOUT FROM KILN 1 (D-82)
Notes: S2.047 - S2.067

Control #: 1 **Description:** BAGHOUSE D-82
Comments: S2.047 - S2.067: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	125,313	tons/yr	1.29	LB/HR	5.635	8736	
PM10	125,313	tons/yr	1.29	LB/HR	5.635	8736	

System Seq#: 28 **Description:** SYSTEM 21 - PRODUCT LIME LOADOUT FROM KILN 2 (DC-230)
Notes: S2.068 - S2.077

Control #: 1 **Description:** BAGHOUSE DC-230
Comments: S2.068 - S2.077: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	199,362	tons/yr	0.69	LB/HR	2.930	8492	
PM10	199,362	tons/yr	0.69	LB/HR	2.930	8492	

System Seq#: 29 **Description:** SYSTEM 22 - PRODUCT LIME LOADOUT FROM KILN 2 (DC-30)
Notes: S2.078 - S2.112

Control #: 1 **Description:** BAGHOUSE DC-30
Comments: S2.078 - S2.112: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	199,362	tons/yr	0.77	LB/HR	3.269	8492	
PM10	199,362	tons/yr	0.77	LB/HR	3.269	8492	

System Seq#: 30 **Description:** SYSTEM 23 - KILN 1 & 2 CYCLONE/BAGHOUSE FINES SILO DISCHARGE
Notes: PF1.037 & PF1.038

Control #: 1 **Description:** SHROUD/CHUTE & WET DUST SUPRESSION
Comments: PF1.037 & PF1.038

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	0	tons/yr	0.0102	LB/TON	0.000	0	Not being used at this time
PM10	0	tons/yr	0.0036	LB/TON	0.000	0	

System Seq#: 31 **Description:** SYSTEM 24 - KILN 1 & 2 CYCLONE/BAGHOUSE COLL. PROD. LOADOUT
Notes: S2.113 & S2.114

Control #: 1 **Description:** BAGHOUSE D-89
Comments: S2.113 & S2.114: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	32,975	tons/yr	0.41	LB/HR	1.741	8492	
PM10	32,975	tons/yr	0.33	LB/HR	1.401	8492	

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System Seq#: 32 **Description:** SYSTEM 25 - KILN 1 & 2 BAGHOUSE FINES SILO DISCHARGE SYSTEM
Notes: S2.224

Control #: 1 **Description:** BAGHOUSE D-11
Comments: S2.224: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	32,975	tons/yr	0.00446	LB/TON	0.074	8736	
PM10	32,975	tons/yr	0.0036	LB/TON	0.059	8736	

System Seq#: 33 **Description:** SYSTEM 26 - KILN 3 BAGHOUSE COLLECTION PRODUCT LOADOUT
Notes: S2.115

Control #: 1 **Description:** BAGHOUSE D-388
Comments: S2.115: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	28,713	tons/yr	0.26	LB/HR	1.104	8492	
PM10	28,713	tons/yr	0.21	LB/HR	0.892	8492	

System Seq#: 34 **Description:** SYSTEM 27 - KILN 3 BAGHOUSE FINES DISCHARGE SYSTEM (D-389)
Notes: S2.116

Control #: 1 **Description:** BAGHOUSE D-389
Comments: S2.116: Flow = dscf/min.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	28,713	tons/yr	0.15	LB/HR	0.637	8492	
PM10	28,713	tons/yr	0.12	LB/HR	0.510	8492	

System Seq#: 35 **Description:** SYSTEM 28 - KILN 3 BAGHOUSE FINES DISCHARGE SYSTEM
Notes: PF1.042

Control #: 1 **Description:** WET DUST SUPRESSION
Comments: PF1.042

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	0	tons/yr	0.00166	LB/TON	0.000	0	Not installed at this time.
PM10	0	tons/yr	0.00078	LB/TON	0.000	0	Not installed at this time.

System Seq#: 36 **Description:** SYSTEM 29 - HYDRATE PLANT SURGE BIN (D-1101)
Notes: S2.117 - S2.119

Control #: 1 **Description:** BAGHOUSE D-1101
Comments: S2.117 - S2.119

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	14,209	tons/yr	0.17	LB/HR	0.143	1683	
PM10	14,209	tons/yr	0.17	LB/HR	0.143	1683	

System Seq#: 37 **Description:** SYSTEM 30 - HYDRATE PLANT HYDRATOR (W-1101)
Notes: S2.120 & S2.121

Control #: 1 **Description:** WET SCRUBBER W-1101
Comments: S2.120 & S2.121 Flow = acf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	18,756	tons/yr	1.98	LB/HR	1.666	1683	
PM10	18,756	tons/yr	1.98	LB/HR	1.666	1683	

System Seq#: 38 **Description:** SYSTEM 31 - HYDRATE PLANT LIME TRANSFER (DC-1132)
Notes: S2.122 - S2.131

Control #: 1 **Description:** BAGHOUSE DC-1132
Comments: S2.122 - S2.131: Flow = dscf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	18,756	tons/yr	0.58	LB/HR	0.488	1683	
PM10	18,756	tons/yr	0.58	LB/HR	0.488	1683	

System Seq#: 39 **Description:** SYSTEM 32 - HYDRATE PLANT LIME TRANSFER TO SILO T-1140
Notes: S2.132 & S2.135

Control #: 1 **Description:** BAGHOUSE D-1140
Comments: S2.132 & S2.135: Flow = dscf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	9,857	tons/yr	0.26	LB/HR	0.219	1683	
PM10	9,857	tons/yr	0.26	LB/HR	0.219	1683	

System Seq#: 40 **Description:** SYSTEM 33 - HYDRATE PLANT LIME TRANSFER TO SILO T-1141
Notes: S2.132 & S2.137

Control #: 1 **Description:** BAGHOUSE D-1141
Comments: S2.132 & S2.137: Flow = dscf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	9,857	tons/yr	0.26	LB/HR	0.219	1683	
PM10	9,857	tons/yr	0.26	LB/HR	0.219	1683	

System Seq#: 41 **Description:** SYSTEM 34 - HYDRATE SILOS LOADOUT
Notes: S2.136 & S2.138

Control #: 1 **Description:** BAGHOUSE D-1142
Comments: S2.136 & S2.138: Flow = dscf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	18,756	tons/yr	0.17	LB/HR	0.022	253	
PM10	18,756	tons/yr	0.17	LB/HR	0.022	253	

System Seq#: 42 **Description:** SYSTEM 35 - PRODUCT LIME KILN 3 - CONTROL DEVICE 1 (DC-331)
Notes: S2.139 - S2.153

Control #: 1 **Description:** BAGHOUSE D-331
Comments: S2.139 - S2.153: Flow = dscf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	287,132	tons/yr	1.03	LB/HR	4.499	8736	
PM10	287,132	tons/yr	0.82	LB/HR	3.582	8736	

System Seq#: 43 **Description:** SYSTEM 36 - PRODUCT LIME KILN 3 - CONTROL DEVICE 2 (DC-333)
Notes: S2.154 - S2.180

Control #: 1 **Description:** BAGHOUSE D-333
Comments: S2.154 - S2.180: Flow = dscf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	143,566	tons/yr	5.57	LB/HR	24.330	8736	
PM10	143,566	tons/yr	4.46	LB/HR	19.481	8736	

System Seq#: 44 **Description:** SYSTEM 37 - PRODUCT LIME KILN 3 - CONTROL DEVICE 3 (DC-343)
Notes: S2.181 - S2.186

Control #: 1 **Description:** BAGHOUSE D-343
Comments: S2.181 - S2.186: Flow = dscf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	143,566	tons/yr	1.37	LB/HR	5.984	8736	
PM10	143,566	tons/yr	1.1	LB/HR	4.805	8736	

System Seq#: 45 **Description:** SYSTEM 38 - PRODUCT LIME KILN 3 - CONTROL DEVICE 4 (DC-361)
Notes: S2.187 & S2.188

Control #: 1 **Description:** BAGHOUSE D-361
Comments: S2.187 - S2.188: Flow = dscf/min

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	143,566	tons/yr	0.51	LB/HR	2.228	8736	
PM10	143,566	tons/yr	0.41	LB/HR	1.791	8736	

System Seq#: 46 **Description:** SYSTEM 39 - COAL STORAGE SYSTEM
Notes: PF1.040 & PF1.041

Control #: 1 **Description:** GOOD OPERATING PRACTICES
Comments: PF1.040 & PF1.041

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM	11,550	tons/yr	0.006	LB/TON	0.035	113	
PM10	11,550	tons/yr	0.0022	LB/TON	0.013	113	

Form must be signed by a Responsible Official or his designee, approved by the Director, pursuant to NAC 445B.156.
Make any changes necessary to the above data. justify any changes by placing comments in the Notes column describing the changes.

System Seq#: 47

Description: EMISSIONS CAP
Notes: Combined HAP emissions for systems 01 - 39 must be < 25 TPY; annual PTE of any individual HAP must be < 10 TPY.

Control #: 1

Description: GOOD OPERATING PRACTICES
Comments: Combined HAP emissions for systems 01 - 39.

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
HAP		tons/yr		LB/TON	14.759		Calculated on separate HAPs page attached.

System Seq#: 48

Description: SURFACE AREA DISTURBANCE
Notes: Fugitive Emissions

Control #: 1

Description: GOOD OPERATING PRACTICES
Comments: Fugitive Emissions

Pollutant	Material/Fuel Throughput Quantity	Units of Measurement (eg. Tons/Yr or MMBtu/Yr etc.)	Emission Factor	Emission Factor Units	Annual Emissions (Tons/Yr)	Hours Operated	Notes
PM10	10	acres		LB/TON			ACTIVE

Form must be signed by a Responsible Official or his designee, approved by the Director, pursuant to NAC 445B.156.
Make any changes necessary to the above data. justify any changes by placing comments in the Notes column describing the changes.

Data Prepared By:

Print Name: Shane Morley

Questions?

Please refer to the enclosed report completion how-to-guide, or access the guide online at http://www.ndep.gov/bapc/permitting/qa/annual_form.pdf

I hereby certify that the above information is true and accurate under penalty of perjury:

Signed:

Print Name: TERRY MCINTYRE

Title: PILOT PEAK PLANT MANAGER

Responsible Official

The "Responsible Official" (RO) indicated above is currently the recognized RO of record for this facility. If the facility's RO has changed, the Nevada Division of Environmental Protection/Bureau of Air Pollution Control (NDEP/BAPC) must be notified in writing of this change by an officer of the company as defined in the NAC 445B.156. If you find that your facility's RO has changed, or needs to be changed, please ensure that the new designee meets the qualifications in 445B.156.1(a)-(d) and have an appropriate company official sign the "Designating Official" signature block below.

If designating a new Responsible Official, please complete this section:

New RO Designee: Title: Designating Official: Title:

The RO designee identified above must meet the qualifications specified in NAC 445B.156.1(a)-(d) (please see Step 4 of the enclosed fact sheet). The NDEP/BAPC will either concur or deny in writing with this designation within 60 days of receipt of this report if a new Responsible Official is designated.

Form must be signed by a Responsible Official or his designee, approved by the Director, pursuant to NAC 445B.156.

Make any changes necessary to the above data. justify any changes by placing comments in the Notes column describing the changes.

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Appendix C

LNA SNCR Technology Michael Best Legal Memo

Michael Best

Memorandum

VIA EMAIL

Client Matter: 212321-9001

To: Hal Lee, Graymont Western US

From: Gayle A. Bush
Todd E. Palmer

Date: March 9, 2021

Subject: LNA SNCR Technology

Graymont Western US Inc. (Graymont) owns and operates the Pilot Peak lime kiln facility located near West Wendover, Nevada. The Pilot Peak Facility achieves low NOx emission rates through the utilization of low NOx burner (LNB) technology in its kilns. Nonetheless, the Nevada Division of Environmental Protection (NDEP) has initially selected the Pilot Peak Facility for an analysis of additional NOx emission control measures that might demonstrate reasonable further progress towards achieving Nevada's visibility improvement goals in the State's Round 2 regional haze SIP. Lhoist North America (LNA) has developed SNCR technology for use on lime kilns and has installed the technology at five facilities. NDEP has suggested that the Pilot Peak Facility also utilize the LNA SNCR technology to further reduce NOx emissions beyond what is already being achieved with LNBs. LNA has informed NDEP that the technology capital costs are approximately $500,000 per kiln to install; however, Graymont believes the costs will be substantially higher.

There is not much information available regarding the LNA SNCR technology or whether LNA has sought or received patents for its technology. Graymont asked Michael Best to conduct a patent search to determine whether LNA has any patents or patent applications for its SNCR technology, and to learn more about the SNCR technology it is pushing regulators to require. In summary, we identified one granted patent that is owned by LNA and is related to use of SNCR technology for NOx emission reduction in a rotary preheater mineral kiln.

We conducted a patent search to identify any US patents or patent applications 1) owned by LNA, or its related companies, and 2) related to SNCR technology. The search yielded about 58 active and 69 expired/abandoned patents/applications for LNA and its related companies. Based on our understanding of SNCR technology, we analyzed the patent search results and identified U.S. Patent No. 7,377,773 ("the '773 Patent") as the only result relevant to SNCR technology.

The '773 Patent was filed on August 3, 2006 by Chemical Lime Company and granted on May 27, 2008. The '773 Patent will expire on September 8, 2026. Post-grant, Chemical Lime Company changed its name to Lhoist North America, Inc.

Generally speaking, the ‘773 Patent relates to a method for reducing NOx emissions from rotary preheater mineral kilns by coupling the temperature control and gas composition afforded by high temperature mixing systems with the injection of nitrogen containing chemical additives at a predetermined location and within an optimal temperature window. The method is specifically directed to rotary preheater limestone kilns.

The ‘773 Patent includes 9 claims that define its invention, and what LNA has the exclusive right to make, use, sell and offer for sale. Two of the claims are independent (claims 1 and 9), which include the broadest recitation of LNA’s invention, and remaining claims 2-8 depend from claim 1.

The ‘773 Patent claims as its invention a method of reducing NOx emissions in a rotary preheater limestone kiln having a feed zone, a preheat zone, a calcining zone and a cooling and discharge zone. Independent claim 1 requires each of the following elements, or an equivalent thereof:

1. Feeding a supply of limestone to the feed zone;
2. Moving the limestone through the preheat zone having a preheat temperature range resulting from the circulation of hot gases from the calcining zone to the preheat zone, the preheated limestone being passed to an upper end of the calcining zone where the limestone is heated to a temperature and for a time sufficient to convert the limestone to quicklime;
3. Introducing a source of ammonia or an ammonia precursor at a point where the temperature in the kiln is within 1600°F to 2200°F;
4. Injecting turbulent air at a preselected point or points downstream of the preheat zone; and
5. Passing the calcined limestone from the calcining zone to the cooling and discharge zone and discharging the resulting quicklime from the kiln.

Independent claim 9 requires elements 1, 2, 4 and 5 listed above for claim 1, or an equivalent thereof, as well as:

6. Introducing a source of ammonia or an ammonia precursor into the limestone upstream of the primary region of the calcining zone;
7. Introducing the source of ammonia or an ammonia precursor at a point where the kiln temperature is generally in the preheat temperature range from about 1600°F to 2200°F.

Because no information is available directly from LNA or NDEP as to what the LNA SNCR technology entails, we are assuming that the LNA SNCR technology mentioned by NDEP is the SNCR technology described and patented by the ‘773 Patent. Therefore, the LNA SNCR technology is not commercially available to Graymont because it is protected by the ‘773 Patent and LNA has the exclusive right to make, use, sell and offer for sale the LNA SNCR technology.

We have not investigated the validity of the ‘773 Patent, nor do we concede the patentability of the LNA SNCR technology. However, because the LNA SNCR technology is patented, it is our belief that LNA will defend its exclusive patent rights if the LNA SNCR technology is implemented by Graymont or at a minimum expect Graymont to take a license to the ‘773 Patent in order to implement the LNA SNCR technology.

If Graymont is required to implement the LNA SNCR technology, it will likely need to do so subject to a license from LNA to the ‘773 Patent as the LNA SNCR technology is not commercially available without a patent license. Any license will likely be subject to a license fee, which will incur additional costs associated with an implementation of the LNA SNCR technology at the Pilot Peak Facility.

Most patent licenses are subject to one or more of the following types of license fees: an up-front license fee, continuous lump sum license fee payments, and/or rolling royalty fee payments. In our experience, license fees are difficult to predict as average fees and rates are typically industry specific, there is uncertainty and changes in market over the term of the patent, and most importantly licenses are subject to negotiation between the licensor and licensee.

Due to the factors listed above, predicting an up-front license fee or continuous lump sum license fee payment is challenging. Estimating potential license fee costs associated with a royalty fee presents challenges as well; however, there are for-fee services available that will provide average royalty rate information on an industry-by-industry basis, as well as by deal-type. These resources can be used as a starting point for estimation purposes.

Under a license based on a reasonable royalty, the fee might be based on a production metric associated with the Pilot Peak Facility and the LNA SNCR technology. For example, the royalty could be based on sales revenue of the final product or a production quantity, such as weight of produced quicklime (e.g., price per pound produced). In our experience, royalties for non-exclusive licenses based on net sales are typically 1% to 5% of the net sales. We did identify one article from an on-line legal service provider (Patent Licensing Royalty Rates | UpCounsel 2020) that referenced an average royalty rate for energy and environmental industries as 8% and construction industries as 5.6%; however, this estimate is based on royalties offered by others in comparable industries and does not truly compare similar deals. Based on the above information, we would guess that a royalty for a license to the ‘773 Patent could be in the range that would add significant expense to the cost of installing and operating the LNA SNCR technology – assuming the patent is valid.

In summary, implementing the LNA SNCR technology at the Pilot Peak Facility would incur additional costs associated with the ‘773 Patent that are beyond the estimated $500,000 per kiln capital cost to install. In order to implement the LNA SNCR technology, Graymont would need to negotiate a license with LNA for use of the technology.

GAB:mgd

Attachments

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Appendix D

Class 4 Engineering Cost Estimate for Pilot Peak SNCR Capital and Operating Costs

Project: Pilot Peak SNCR Estimate

Budget Class 4
Revised: 2019-04-10
By: Sean Brinkmann

Description	References	Qty	Unit	Material & Equipment Unit cost	Material & Equipment Cost	Qty	unit	Installation Unit cost	Installation Cost	TOTAL K1	TOTAL K2	TOTAL K3	Comments
Penta Project Cost Estimate													
Contractor General									76,450 $	76,450 $	76,290 $	76,290 $	
Construction l Equipment									75,600 $	75,600 $	75,600 $	75,600 $	
Civil Site Work, Parking Area and Road (Gravel access and parking for offloading delivery truck)					6,367 $				6,600 $	12,967 $	12,967 $	12,967 $	
Fire Water Extension Allowance		100	lnFT		5,249 $				4,143 $	9,392 $	9,392 $	9,392 $	
Ammonia Tank Piers, Secondary Containment, Roof Structure, and Pump Pad					50,952 $				45,800 $	96,752 $	60,051 $	60,051 $	only one pump skid and that is with Kiln 1.
Fencing					16,000 $				4,600 $	20,600 $	0 $	0 $	With Kiln 1
Ammonia Tank and Pump, Meter Systems		20000	gal		284,600 $				39,080 $	323,680 $	305,170 $	305,170 $	Kiln 2 requires pipe header from tank to pumps
Refractory Repair Inside Kiln	Not Included									not included	not included	not included	assumed to be with other Kiln repair costs
Pipe 2" dia. from Truck Unload to Storage Tank		50	lnFT		3,152 $				2,750 $	5,902 $	5,202 $	5,202 $	
Pipe 2" dia from Tank to Preheater Transfer Pumps		50	lnFT		5,498 $				3,410 $	8,908 $	8,908 $	8,908 $	assumed to be with other Kiln repair costs
Pipe 1.5" dia. from Pumps to Preheater		550	lnFT		24,719 $				18,904 $	43,623 $	42,900 $	42,900 $	Kiln 2 has longer pipe length. Kiln 1 has 2 NH3 monitors for pipe in concrete trench
Pipe 2" dia Up Preheater to Injection		100	lnFT		3,876 $				3,777 $	7,653 $	6,448 $	6,448 $	
Compressed Air Tap, Piping, Receiver and Water Duel Basket Strainer, Water Pipe		200	lnFT		31,851 $				21,933 $	53,784 $	28,784 $	28,784 $	
Install Injection Nozzles in Chute Below Preheater		4	ea.		5,197 $				7,847 $	13,043 $	13,043 $	13,043 $	
Electrical		1	lot		63,383 $				63,382 $	126,765 $	92,482 $	92,482 $	Kiln 1 has truck unload pumps
Controls	By Andritz						hrs.	0 $		By Andritz	By Andritz	By Andritz	
TOTAL FOR Penta Base Estimate										**875,120 $**	**737,236 $**	**737,236 $**	
Penta Indirect Cost Estimate													Contingency carried on total project, not specific segments to not compound contingency
Taxes										not included	not included	not included	
Freight	5%								16,184 $	16,184 $	16,184 $	16,184 $	
Permits									35,000 $	35,000 $	with Kiln 1	with Kiln 1	
Geotechnical									10,000 $	10,000 $	with Kiln 1	with Kiln 1	
Surveys / Scans									20,000 $	20,000 $	with Kiln 1	with Kiln 1	
Contractor Support During Commission		1	lot				hrs.	0 $	31,020 $	31,020 $	31,020 $	31,020 $	
NDT Pipe Inspection									10,000 $	10,000 $	10,000	10,000	
Engineering	15%									131,268 $	65,634 $	65,634 $	
Contractor Overhead and Profit	10%									112,859 $	86,007 $	86,007 $	
TOTAL Penta Indirect Cost Estimate										**366,331 $**	**208,845 $**	**208,845 $**	
Andritz Automation Controls Estimate													
PLC Equipment									35,000 $	11,667 $	11,667 $	11,667 $	Price for all 3 Kilns
Instruments									9,100 $	3,033 $	3,033 $	3,033 $	Price for all 3 Kilns
MCC									23,900 $	7,967 $	7,967 $	7,967 $	Price for all 3 Kilns
Detailed Design & Programming									54,400 $	18,133 $	18,133 $	18,133 $	Price for all 3 Kilns
Site Services and Expenses									33,700 $	11,233 $	11,233 $	11,233 $	Price for all 3 Kilns
TOTAL FOR Controls Estimate										**52,033 $**	**52,033 $**	**52,033 $**	
Penta Excluded Equipment													
Air Compressor, Dryer & Receivers		1	lot	80,176 $	80,176 $	60	hrs.	55 $	3,300 $	27,825 $	27,825 $	27,825 $	Connecting to exiting air system for use of exiting pipe for distrobution
Contractor Overhead and Profit	10%									2,783 $	2,783 $	2,783 $	
TOTAL FOR Penta Excluded Equipment										**30,608 $**	**30,608 $**	**30,608 $**	

CEMS												
Project Management and Administration						1	lot	20,000 $	20,000 $	20,000 $	with Kiln 1	with Kiln 1
- Equipment & Install												
Thermo 42iQ NOx analyzers	CEMS Solutions Quote	1	ea.	15,140 $	15,140 $					15,140 $	15,140 $	15,140 $
CEMS Provider Start-up, training, and Administration	CEMS Solutions Quote					1	lot	14,573 $	14,573 $	14,573 $	with Kiln 1	with Kiln 1
Unisearch Dual Range NH3 TDL, integrate into exiting CEMS	MSI Quote	1	ea.	90,000 $	90,000 $					90,000 $	90,000 $	90,000 $
CEMLink DAS programming and configuration NH3	VIM Budget Quote					1	lot	10,500 $	10,500 $	10,500 $	with Kiln 1	with Kiln 1
NH3 TDL Installation						1	ea.	5,000 $	5,000 $	5,000 $	5,000 $	5,000 $
- Commissioning & CEMS Certification Costs												
Mobilization and one week FTIR shakedown testing to assess injection lance placement, NOX and NH3 measurement performance etc.	Eric Ehlers, Mostardi Platt communication					1	lot	33,000 $	33,000 $	33,000 $	with Kiln 1	with Kiln 1
Laura Kinner Ph. D. oversight and review of shakedown and RATA FTIR testing of FTIR						1	lot	5,000 $	5,000 $	5,000 $	with Kiln 1	with Kiln 1
Incremental cost for NOx and NH3 RATA testing for three kilns if performed during annual compliance test	Eric Ehlers, Mostardi Platt communication					1	lot	10,000 $	10,000 $	10,000 $	with Kiln 1	with Kiln 1
MSI on-site for RATA test						1	lot	8,000 $	8,000 $	8,000 $	with Kiln 1	with Kiln 1
Graymont time for training in O&M, technical requirements, and reporting recordkeeping	16 hours technician, 16 hours Envr. Management					32	hr.	88 $	2,800 $	2,800 $	with Kiln 1	with Kiln 1
Graymont time for 7-day calibration drift tests and calibration error tests for certification and reporting for three kilns	24 hours technician, 12 hours Envr. Management					36	hr.	83 $	3,000 $	3,000 $	with Kiln 1	with Kiln 1
Update QA manual for NOx and NH3 additions (does not include technical procedures or corrective action to be provided by MSI)	VIM Budget Quote					1	lot	1,000 $	1,000 $	1,000 $	with Kiln 1	with Kiln 1
Corrective action and technical procedures for NH3 monitors						1	lot	5,000 $	5,000 $	5,000 $	with Kiln 1	with Kiln 1
- Condensable Particulate Issues												
Diagnostic testing to determine effects of SNCR reagent injection on formation of condensable PM. Test two kilns at three conditions each: (injection off, low injection, high injection). Two test crews for three test days with mobilization and reporting	Eric Ehlers, Mostardi Platt communication					1	lot	40,000 $	40,000 $	40,000 $	with Kiln 1	with Kiln 1
Review and analysis of data, and EMI theoretical calculations. Graymont negotiation of Condensable PM permit limit.						1	lot	20,000 $	20,000 $	20,000 $	with Kiln 1	with Kiln 1
TOTAL FOR CEMS										**283,013 $**	**110,140 $**	**110,140 $**
Sub-Total										**1,576,497 $**	**1,108,255 $**	**1,108,255 $**
Contingency						10%				157,650 $	110,825 $	110,825 $
TOTAL =										**1,734,147 $**	**1,219,080 $**	**1,219,080 $**

All Three Kilns Before Contingency	3,793,007 $
Contingency Total	379,301 $
Grand Total	**4,172,307 $**

Annual Operating Costs

Description	References	Qty	Unit	Material / Vendor		Qty	unit	Plant Labor/Staff		TOTAL	Comments
				Unit cost	Cost			Unit cost	Cost		
Delivered Ammonia (6000 gal Truck)	Airgas Quote	385	Trucks	8,418 $	3,240,930 $					3,240,930 $	
Pump & valve rebuilds and maintenance		4	ea.	1,500 $	6,000 $	80	hr.	75 $	6,000 $	12,000 $	20hrs/pump skid (3 injection & 1 transfer pump skid)
Daily Inspection Ammonia Tank & Pump skids						182	hr.	75 $	13,650 $	13,650 $	30 minutes per day x 7 days per week of Kiln attendant
Power Consumption - Compressor - 50HP		245939	KW	0.06 $	15,937 $					15,937 $	Assumes operating 70% of the year
Power Consumption - Injection Pumps (10 HP x3)		189725	KW	0.06 $	12,294 $					12,294 $	Assumes operating 90% of the year
Power Consumption - Blowers (10 HP x3)		189725	KW	0.06 $	12,294 $					12,294 $	Assumes operating 90% of the year
- On-going Annual Costs for O&M Reporting and Recordkeeping											
Annual calibration gases SO2/NOx blends and NH3 audit gases plus Graymont management									2,500 $	2,500 $	
Daily cal drift check review and brief inspection						260	hr.	75 $	19,500 $	19,500 $	20 minutes per day x three kilns x 5 days per week of technician time
Preventive maintenance and corrective action						144	hr.	75 $	10,800 $	10,800 $	4 hrs. per months x 3 kilns x 12 months of technician time
Monthly data review & reports to management re NOx emissions, NH3 slip, CEMS availability						108	hr.	100 $	10,800 $	10,800 $	3 hours per month x 3 kilns x 12 months of Envr. Management time
Quarterly NH3 cylinder gas audits, laser alignment, and preventive maintenance by MSI (2 days on-site plus travel expenses) with Graymont technician support		4	qtr.	8,000 $	32,000 $	64	hr.	75 $	4,800 $	36,800 $	MSI communication (assume $8000 per quarter) plus 16 hours Graymont technician time
VIM DAS incremental annual maintenance cost	Vim Budget quote	1	lot	500 $	500 $					500 $	
Mobilization and one week annual FTIR RATA testing for NOx and NH3 CEMS for three kilns		1	lot	33,000 $	33,000 $	50	hr.	90 $	4,500 $	37,500 $	Eric Ehlers Mostardi Platt communication plus 20 hours technician support and 30 hours Envr. Management coordination, report review and submission
Semi-Annual reporting of regulatory NOx monitoring results, QA results, CEMS downtime						36	hr.	100 $	3,600 $	3,600 $	6 hours per kiln per report of Envr. Management time
Semi-Annual reporting of regulatory NH3 monitoring results, QA results, CEMS downtime if regulatory monitor						36	hr.	100 $	3,600 $	3,600 $	6 hours per kiln per report of Envr. Management time
TOTAL FOR COAL HANDLING										**3,432,705 $**	
Sub-Total										**3,432,705 $**	
Contingency						10%				343,271 $	
TOTAL =										**3,775,976 $**	

https://graymont-my.sharepoint.com/personal/sbrinkmann_graymont_com/Documents/Desktop/Pilot SNCR Project/Estimate to Combine/PDFs/Graymont Estiamte Combined.xlsx

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Appendix E

Graymont Process Engineering Temperature and Residence Time Calculations

PP TCH Modeling Residence Time and Temperatures

Summary Avg. TCH Temperatures					
Description	Units	K1	K2	K3	Comments
Avg. Production Rate	TPD	377	617	766	Source: Feb 2020-Feb 2021 ODE Production Data
Estimated Gas Vol. Flow Rate	ACFM	98,113	161,021	201,121	@ kiln feed, 36%CO2 and 1811 F K1, 1819 F K2, 1833 F K3
Estimated Residence Time	sec	0.42	0.79	0.68	Transfer Chute Nozzle Location-Preheater stone contact
Max. Production Rate	TPD	549	791	1,008	Source: Feb 2020-Feb 2021 ODE Production Data
Estimated Gas Vol. Flow Rate	ACFM	142,749	206,397	264,635	@ kiln feed, 36%CO2 and 1811 F K1, 1819 F K2, 1833 F K3
Estimated Residence Time	sec	0.29	0.61	0.51	Transfer Chute Nozzle Location-Preheater stone contact

Average RT (sec) for Avg. TCH Temp **0.55**

Summary Max. TCH Temperatures					
Description	Units	K1	K2	K3	Comments
Avg. Production Rate	TPD	377	617	766	Source: Feb 2020-Feb 2021 ODE Production Data
Estimated Gas Vol. Flow Rate	ACFM	105,976	163,141	213,401	@ kiln feed, 36%CO2 and 1993 F K1, 1849 F K2, 1973 F K3
Estimated Residence Time	sec	0.39	0.78	0.64	Transfer Chute Nozzle Location-Preheater stone contact
Max. Production Rate	TPD	549	791	1,008	Source: Feb 2020-Feb 2021 ODE Production Data
Estimated Gas Vol. Flow Rate	ACFM	154,189	209,114	280,792	@ kiln feed, 36%CO2 and 1993 F K1, 1849 F K2, 1973 F K3
Estimated Residence Time	sec	0.27	0.60	0.48	Transfer Chute Nozzle Location-Preheater stone contact

Average RT (sec) for Max. TCH Temp **0.53**

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October 15, 2021

Via Electronic Mail

Mr. Steven McNeece
Environmental Scientist
Nevada Division of Environmental Protection
Department of Conservation and Natural Resources
901 S. Stewart Street, Suite 4001
Carson City, NV 89701
smcneece@ndep.nv.gov

RE: Graymont Pilot Peak Response to the Initial Control Determination Letter

Dear Mr. McNeece:

Graymont Western US, Inc. (Graymont) submits this response to the "2021 Regional Haze Four Factor Review and Initial Control Determination Facility: Graymont Western US, Inc., Pilot Peak Plant" prepared by the Bureau of Air Quality Planning, Nevada Division of Environmental Protection (NDEP) and received by Graymont on October 6, 2021 (Initial Analysis). The Initial Analysis is NDEP's review and determination of the 4-factor analysis submitted for the Pilot Peak Plant operated by Graymont.

Pilot Peak Should Be Excluded from the Second Implementation Period Submittal

NDEP has been clear and transparent in its communication with the public and regulated community on how it would develop its state implementation plan submittal to show reasonable progress on regional haze for the second implementation period. Since initiating the process, NDEP has committed to use the Q/d analysis as its screening tool for identifying those Nevada stationary sources that have the potential to meaningfully impact visibility on a Class I area and therefore warrant undergoing the resource intensive 4-facotr analyses.

In a presentation on October 6, 2010, NDEP explained that although other Western States were using a Q/d threshold of 10 to identify sources that must undertake a 4-factor analysis, NDEP wanted to be "a little bit more conservative" and use a factor of

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5. NDEP explained that this would give them a wider range of facilities to examine and ensure a broad geographic diversity in the facilities being examined. At that time NDEP had calculated the Pilot Peak Facility's Q/d as being 5.15. The next lowest Q/d score calculated by NDEP was Nevada Cement at 14.55. Clearly NDEP's decision to reduce the Q/d threshold from 10 to 5 was intended to capture just one facility, Pilot Peak.

Yet, as is discussed in Appendix B of the Initial Analysis, NDEP's initial Q/d calculation for Pilot Peak was wrong. The correct Q/d value is merely 4.61. This is extremely low and well outside the level that would trigger a 4-factor analysis in Nevada, or virtually anywhere in the country. This is not mere coincidence, but rather attributable to Graymont voluntarily and purposely reducing NOx emissions at Pilot Peak years ago.

Graymont thanks NDEP for its candor in acknowledging this error and respectfully asks that it now follow the rules it set forth at the beginning of this process. Just like all other sources in the state with a Q/d value of less than 5, NDEP must conclude that Pilot Pike causes minimal, if any, visibility impacts to a Class I area. Also like these other sources, Pilot Peak should be excluded from the state implementation plan submittal.

It is obvious that the Pilot Peak Facility would not have been included in the second planning period had NDEP not utilized an incorrect emissions value when calculating the Facility's Q/d value. Because of this error, Graymont has already incurred significant costs associated with assembling the four-factor analysis, obtaining cost estimates, assembling additional follow-up correspondence, including significant consultation fees and hundreds (perhaps over 1000) internal Graymont manhours that should not have been incurred.

Given this error and NDEP's clear statement to exclude sources with a Q/d value less 5, Graymont respectfully requests the Department reconsider its position to include Graymont in this second regional haze planning period and omit Pilot Peak from the regional haze second implementation plan. NDEP's own directives and the requirement to treat all sources similarly requires it.

The NDEP Proposed NOx Limits are Inappropriate

Graymont is adamant that Pilot Peak be removed from the second planning period, However, Graymont is willing to work with NDEP to establish enforceable, lower Nitrogen Oxide (NOx) permit limits for the three Pilot Peak kilns that reflect the use of low NOx burners (LNB). However, the limits proposed by NDEP are too low and do

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not adequately consider the data from the applicable kiln stack tests. NDEP must account for the variability in these stack test results to set limits for which Graymont can demonstrate consistent compliance.

Graymont has conducted an analysis and identified proposed limits that are slightly higher than NDEP's proposal, but provide a 99.7% confidence level (3 sigma) based on a normal distribution of the test data. This is based on taking the average of the stack test results for each kiln and adding three standard deviations to derive a proposed permit limit. This is a common and widely accepted means of establishing permit limits with a comfortable margin of compliance for a permitee.

The limits proposed by NDEP propose standards that Graymont would not reasonably be able to consistently maintain given the established variability in the stack tests. Rather, the permit limits suggested by the Department, based on the data available today, would create a material compliance demonstration risk of permit exceedance if established. Graymont cannot agree to limits that objectively cannot be met on a consistent basis.

Graymont proposes the use of a 3 sigma / 99.7% confidence approach that, when converted into days per year, provides reasonable confidence that 364 days per year will be in compliance (365 days X 0.997 = 363.9). Emission limits lower than this which do not account for the variation of the available data will place an undue and unacceptable compliance demonstration burden on the facility as Graymont and the Department expect the facility to maintain ongoing compliance in line with reasonably established limits.

Graymont has conducted an evaluation of the data associated with the recent annual stack tests - Table 1.

Table 1. Kiln NOx lb/hour values from annual compliance demonstration stack tests by year

Year	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Kiln 1	43.50	47.5	40.00	57.60	34.99	44.61	43.0	74.18
Kiln 2	74.60	40.1	51.50	35.56	74.05	37.21	57.7	90.16
Kiln 3	58.30	60.2	44.40	67.12	44.90	89.53	102.4	108.09

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Table 2 contains the proposed NOx limits for the Pilot Peak kilns derived by conducting this analysis described above with a 99.7% confidence level.

Table 2. Proposed Permit Limit Values for Low NOx Burners

Kiln	Average Value	Standard Deviation (StDev)	**Proposed Permit Limits** (Avg + 3 StDev)	Percent NOx Reduction from existing Limits
1	48.2	12.3	**85.2**	29%
2	57.6	20.2	**118.3**	26%
3	71.9	25.0	**146.9**	27%

The limits proposed in Table 2 provide a reasonable degree of compliance assurance. Yet, these limits also reflect a significant reduction from the existing Pilot Peak NOx permit limits - 29%, 26%, and a 27% reduction for Kiln 1, 2 and 3 respectively.

Miscellaneous

In Section 2, kiln one is listed as having a rating of 24 tons per hour. This should be corrected to 25 tons per hour as is reflected in the current permit.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call me at 814-353-2106.

Kind regards,

John Maitland
Director, Corporate Affairs, Environment & Sustainability North America

cc: Sigurd Jaunarajs, NDEP
Terry McIntyre, Graymont
Hal Lee, Graymont
Nate Stettler, Graymont

Appendix B.3 - TS Power Plant, Nevada Newmont Energy Investment

Appendix B.3.a	NDEP Reasonable Progress Control Determination for TS Power Plant
Appendix B.3.b	Nevada Newmont Energy Investment Reasonable Progress Analysis for TS Power Plant

Appendix B.3.a - NDEP Reasonable Progress Control Determination for TS Power Plant

TS Power Plant Reasonable Progress Control Determination

Evaluation of existing and potential new control measures at Newmont Nevada Energy Investment's TS Power Plant necessary to achieve reasonable progress for Nevada's second Regional Haze SIP.

Bureau of Air Quality Planning, Nevada Division of Environmental Protection

March 2022

1 Introduction

This document serves as the official reasonable progress determination for the TS Power Plant based on analyses submitted by the owner of the facility. The Long-Term Strategy of Nevada's Regional Haze SIP revision for the second implementation period covering years 2018 through 2028 will rely on the reasonable progress findings of this document.

This reasonable progress determination references data and analyses provided by Newmont Nevada Energy Investment (NNEI) in multiple documents that can be found in Appendix B.3. Table 1-1 below outlines the documents submitted by NEII that supplement this determination document. In some cases, the Nevada Division of Environmental Protection (NDEP) adjusted information submitted by NNEI to ensure the analyses relied on to make reasonable progress determinations agree with Regional Haze Rule regulatory language, Regional Haze Rule Guidance for the second implementation period, and EPA's Control Cost Manual. Throughout the document, it can be assumed that referenced data and information rely on the following documents submitted by NNEI, unless explicitly indicated that NDEP made adjustments.

Table 1-1: NNEI Documents Relied upon for Reasonable Progress Determination

Full Document Title	Shortened Document Title (used in this document)	Date	Appendix Location
Reasonable Progress Analysis	*NNEI Analysis*	December 10, 2019	B.3.b

2 Facility Characteristics

The TS Power Plant, operated by Newmont Nevada Energy Investment (NNEI), LLC, is located in northern Nevada, approximately 135 miles away from the nearest class I area, Jarbidge Wilderness Area. The facility was granted a construction permit by NDEP on May 5, 2005 and began commercial operation on May 1, 2008. The facility has one pulverized coal, dry bottom boiler with a gross capacity of 220 MW.

3 Emissions Profile

3.1 Q/d Emissions Profile

NDEP relied on the Q/d method for source selection by quantifying total facility-wide NO_x, SO_2, and PM_{10} emissions, represented as "Q", reported in the 2014 NEIv2. The Q value was then divided by the distance, in kilometers, between the facility and the nearest Class I area (CIA), represented as "d". The nearest CIA to the TS Power Plant is Jarbidge Wilderness Area at 131 kilometers away. NDEP elected to set a Q/d threshold of 5. As displayed in Table 3-1, using 2014 NEIv2 emissions, the Pilot Peak Plant yielded a Q/d value of 6.37, effectively screening the facility into a four-factor analysis requirement for the second round of Regional Haze in Nevada.

Table 3-1: TS Power Plant Q/d Derivation

NO_x Emissions (tpy)	SO_2 Emissions (tpy)	PM_{10} Emissions (tpy)	Total Q (NO_x+SO_2+ PM_{10})	Distance from Nearest CIA (Jarbidge WA) [km]	Q/d
334	234	266	834	131	6.37

4 Screening TS Power Out of Four-Factor Analysis Requirement

The EPA Regional Haze Guidance document indicates certain criteria that may be relied on to determine a source already has effective controls, and that a four-factor analysis would likely result in no additional controls being technically feasible or necessary to achieve reasonable progress. NNEI has listed the criteria and how it is applicable to the TS Power Plant to conclude that the facility already has the Best Available Control Technology (BACT) and should be screened out of a four-factor analysis requirement. NDEP is relying on Section 3 and 4 of the *NNEI Analysis* to determine that the TS Power Plant is an effectively controlled source based on the following considerations:

- New Source Performance Standards (*Section 3.1 NNEI Analysis)*
- Best Available Control Technology *(Section 3.2 NNEI Analysis)*
- SO2 Control Measures *(Section 3.3 NNEI Analysis)*
- National Emission Standards for Hazardous Air Pollutants *(Section 3.4 NNEI Analysis)*
- BACT Review *(Section 4 NNEI Analysis)*

NDEP agrees that the TS Power Plant is an effectively controlled source that should be screened out of the four-factor analysis requirement as it is reasonable to assume that any such analysis would likely result in no additional controls being technically feasible or necessary to achieve reasonable progress.

Although no new measures were formally considered to achieve reasonable progress at the TS Power Plant, NDEP still evaluated whether any existing measures at the facility were necessary to achieve reasonable progress, outlined in the following sections.

5 PM_{10} Determination for Existing Measures

TS Power currently operates a Pulse Jet Fabric Filter Dust Collector for the control of particulate matter.

5.1 Weight-of-Evidence Demonstration

NDEP is relying on the following weight-of-evidence demonstration to conclude that the source's existing measures to control PM_{10} emissions are not necessary to achieve reasonable progress during the second implementation period of the Regional Haze Rule in Nevada.

5.1.1 Historical Emission Rates

The following annual PM_{10} emission rates were reported by NNEI for the boiler at the TS Power Plant from 2016 through 2020, representing data from the most recent five operating years (see Table 5-1). The most recent five years show a consistent PM_{10} emission rate for the facility's boiler. NDEP considers the trend in PM_{10} emission rates outlined in Table 5-1 as reasoning to assume that the source's achievable emission rates will remain consistent and not increase in the future.

Table 5-1: Historical PM_{10} Achievable Emission Rate Profile for TS Power Boiler

	Reported Annual PM_{10} Emission Rates (lb/MMBtu)					
	2016	**2017**	**2018**	**2019**	**2020**	**2016-2020 Average**
Boiler 1	0.015	0.0091	0.02	0.019	0.0082	0.0143

5.1.2 Projected Emission Rates

There are no federally enforceable on-the-way controls or changes to operations at the TS Power Plant. Because of this, NDEP finds it reasonable to rely on emissions and emission rates calculated from the 2016-2020 representative historical period to project future emissions and emission rates. As stated in Table 5-1, the representative historical period, and projection assumption, for the boiler's PM_{10} emission rate is 0.0143 pounds of PM_{10} per million British thermal units. NDEP concludes that the projected emission rate will remain consistent with historical emission rates.

Table 5-2 outlines the boiler's annual PM_{10} emissions reported from 2016 through 2020, along with the annual average among the evaluated years. NDEP is relying on the 2016-2020 average annual emissions to represent projected annual emissions and concludes that the projected PM_{10} emissions of 59 tons per year will remain consistent with historical PM_{10} emissions.

Table 5-2: Historical Annual PM_{10} Emissions Profile for TS Power Boiler

Reported Annual PM_{10} Emissions (tons per year)					
2016	**2017**	**2018**	**2019**	**2020**	**2016-2020 Average**
71.2	47.7	20.8	107.5	48.9	59.2

5.1.3 Enforceable Emission Limits

NDEP is citing the following enforceable emissions limits listed in the facility's current air quality operating permit to control PM_{10} emissions that reflect the source's existing measures as evidence that the source will continue to implement the Pulse Jet Fabric Filter Dust Collector.

From Section VI.A.2.a.(2) of NDEP Permit No. AP4911-2502:

"NAC 445B.2203(1)(b) *Federally Enforceable SIP* – The discharge of PM_{10} to the atmosphere will not exceed **0.176 pound per million Btu**."

6 SO_2 Determination for Existing Measures

TS Power currently operates a Lime Spray Dryer dry scrubbing system for the control of SO_2 emissions.

6.1 Weight-of-Evidence Demonstration

NDEP is relying on the following weight-of-evidence demonstration to conclude that the source's existing measures to control SO_2 emissions are not necessary to achieve reasonable progress during the second implementation period of the Regional Haze Rule in Nevada.

6.1.1 Historical Emission Rates

The following annual SO_2 emission rates were reported by NNEI for the boiler at the TS Power Plant from 2016 through 2020, representing data from the most recent five operating years (see Table 6-1). The most recent five years show a consistent SO_2 emission rate for the facility's boiler. NDEP considers the trend in SO_2 emission rates outlined in Table 6-1 as reasoning to assume that the source's achievable emission rate will remain consistent and not increase in the future.

Table 6-1: Historical SO_2 Achievable Emission Rate Profile for TS Power Boiler

	Reported Annual SO_2 Emission Rates (lb/MMBtu)					
	2016	**2017**	**2018**	**2019**	**2020**	**2016-2020 Average**
Boiler 1	0.016	0.025	0.027	0.010	0.017	0.019

6.1.2 Projected Emission Rates

There are no federally enforceable on-the-way controls or changes to operations at the TS Power Plant. Because of this, NDEP finds it reasonable to rely on emissions and emission rates calculated from the 2016-2020 representative historical period to project future emissions and emission rates. As stated in Table 6-1, the representative historical period, and projection assumption, for the boiler's SO_2 emission rate is 0.019 pounds of SO_2 per million British thermal units. NDEP concludes that the projected emission rate will remain consistent with historical emission rates.

Table 6-2 outlines the boiler's annual SO_2 emissions reported from 2016 through 2020, along with the annual average among the evaluated years. NDEP is relying on the 2016-2020 average annual emissions to represent projected annual emissions and concludes that the projected SO_2 emissions of 115 tons per year will remain consistent with historical SO_2 emissions.

Table 5-2: Historical Annual SO_2 Emissions Profile for TS Power Boiler

Reported Annual SO_2 Emissions (tons per year)					
2016	**2017**	**2018**	**2019**	**2020**	**2016-2020 Average**
119	152	146	56	101	115

6.1.3 Enforceable Emission Limits

NDEP is citing the following enforceable emissions limits listed in the facility's current air quality operating permit to control SO_2 emissions that reflect the source's existing measures as evidence that the source will continue to implement the Lime Spray Dryer.

From Section VI.A.2.a.(7) of NDEP Permit No. AP4911-2502:

"NAC 445B.2203(1)(b) _Part 70 Program BACT Emission Limit_ – The discharge of SO_2 to the atmosphere will not exceed:

> (i) While Combusting coal with a Sulfur content equal to or greater than **0.45 percent** (30-day rolling period), based on daily ASTM sampling:
>
> > (a) **0.09 pound per million Btu,** based on a 24-hour rolling average period.
> >
> > (b) 95% minimum SO_2 removal efficiency will be maintained across the system, based on a 30-day rolling period.

(ii) While combusting goal with a Sulfur content less than **0.45 percent** (30-day rolling period), based on daily ASTM sampling:

(a) **0.065 pound per million Btu,** based on a 24-hour rolling average period.

(b) 91% minimum SO_2 removal efficiency will be maintained across the system, based on a 30-day rolling period."

7 NO_x Determination for Existing Measures

TS Power currently operates a Selective Catalytic Reduction (SCR) system, Low NO_x coal burners and over-fire air for the control of NO_x emissions.

7.1 Weight-of-Evidence Demonstration

NDEP is relying on the following weight-of-evidence demonstration to conclude that the source's existing measures to control NO_x emissions are not necessary to achieve reasonable progress during the second implementation period of the Regional Haze Rule in Nevada.

7.1.1 Historical Emission Rates

The following annual NO_x emission rates were reported by NNEI for the boiler at the TS Power Plant from 2016 through 2020, representing data from the most recent five operating years (see Table 7-1). The most recent five years show a consistent NO_x emission rate for the facility's boiler. NDEP considers the trend in NO_x emission rates outlined in Table 7-1 as reasoning to assume that the source's achievable emission rate will remain consistent and not increase in the future.

Table 6-1: Historical NO_x Achievable Emission Rate Profile for TS Power Boiler

	Reported Annual NO_x Emission Rates (lb/MMBtu)					
	2016	**2017**	**2018**	**2019**	**2020**	**2016-2020 Average**
Boiler 1	0.059	0.053	0.057	0.038	0.039	0.049

7.1.2 Projected Emission Rates

There are no federally enforceable on-the-way controls or changes to operations at the TS Power Plant. Because of this, NDEP finds it reasonable to rely on emissions and emission rates calculated from the 2016-2020 representative historical period to project future emissions and emission rates. As stated in Table 7-1, the representative historical period, and projection assumption, for the boiler's NO_x emission rate is 0.049 pounds of NO_x per million British thermal units. NDEP concludes that the projected emission rate will remain consistent with historical emission rates.

Table 7-2 outlines the boiler's annual NO_x emissions reported from 2016 through 2020, along with the annual average among the evaluated years. NDEP is relying on the 2016-2020 average annual emissions to represent projected annual emissions and concludes that the projected NO_x emissions of 257 tons per year will remain consistent with historical NO_x emissions.

Table 5-2: Historical Annual NO_x Emissions Profile for TS Power Boiler

Reported Annual NO_x Emissions (tons per year)

2016	2017	2018	2019	2020	2016-2020 Average
233	257	349	215	233	257

7.1.3 Enforceable Emission Limits

NDEP is citing the following enforceable emissions limits listed in the facility's current air quality operating permit to control NO_x emissions that reflect the source's existing measures as evidence that the source will continue to implement the SCR with Low NO_x coal burners and over-fire air.

From Section VI.A.2.a.(10) of NDEP Permit No. AP4911-2502:

"NAC 445B.305 *Part 70 Program BACT Emission Limit* – The discharge of NO_x (oxides of nitrogen) to the atmosphere will not exceed **0.067 pound per million Btu**, based on a 24-hour rolling period."

8 Reasonable Progress Determination

NDEP concludes that both existing and new control measures at the TS Power Plant boiler are not necessary to make reasonable progress during the second implementation period of Nevada's Regional Haze SIP.

Appendix B.3.b - Nevada Newmont Energy Investment Reasonable Progress Analysis for TS Power Plant

Reasonable Progress Analysis

Newmont Nevada Energy Investment, LLC - TS Power Plant

Project number: 60617981

December 10, 2019

Quality information

Prepared by	Checked by	Verified by	Approved by
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Revision History

Revision	Revision date	Details	Authorized	Name	Position
v00_01	Dec 10, 2019	Final Report		Denise Hazelman	Project Manager

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1. Source Description

Newmont Nevada Energy Investment, LLC owns and operates the TS Power Plant (TSPP). TSPP is a modern, very well controlled coal fired power plant with a capacity of 220 MW gross. A construction permit for the project was issued on May 5, 2005 and commercial operation began on May 1, 2008. The plant site is in northern Nevada, approximately 135 miles from the nearest Class I area, as shown in Figure 1.

TSPP has one pulverized coal, dry bottom boiler burning low sulfur Powder River Basin (PRB) coal. A side view of the boiler showing particulate matter, sulfur dioxide (SO_2), and nitrogen oxides (NOx), emission controls is presented in Figure 2. Emission controls are also listed below:

- PM/PM_{10}: pulse jet fabric filter.
- SO_2: use of low sulfur PRB coal and a spray dryer absorber as post-combustion control.
- NOx: Babcock and Wilcox DRB-4Z® low NOx burners with ignitors and an overfire air system. Post combustion control by selective catalytic reduction with ammonia injection.

2. Emissions

EPA guidance recommends that reasonable progress determination for the second implementation period of the regional haze rule be based on actual emissions for a representative historical period.[1] TSPP boiler's actual emissions for the 2016 through 2018 period are presented in Table 1. Total combined annual emissions of total PM/PM_{10}[2], SO_2, and NO_X were only 500 tons/year (ton/yr).

The significance of a source's emissions of PM/PM_{10}, SO_2, and NO_X are often based on a screening technique known as Q/d where "Q" is the source's total annual emissions (ton/yr) and "d" is the distance in kilometers to the nearest Class I area. EPA guidance suggests that Q/d may be used to develop a list of sources for which a four-factor analysis may be conducted.[3] However, EPA guidance does not suggest a threshold value for Q/d. In the past regional haze programs and air permitting, sources with a Q/d less than 10 have often been screened out from a detailed analysis.

The Western Regional Air Partnership (WRAP) also has the following guidance on the use of Q/d:

> "Accordingly, consistent with the FLAG guidelines, the Subcommittee suggests that states should first screen sources at a Q/d > 10 level to determine if a reasonable number of sources are identified for further review. If no sources are identified, the Subcommittee recommends stepping down the Q/d screening level in increments of one until a reasonable number of sources are identified for further review."[4]

[1] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019. Page 17
[2] Emissions are based on stack testing. The available data are total PM/PM_{10} based on EPA Methods 5 and 202. For conservatism, all PM is assumed to be PM_{10}.
[3] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019. Page 13
[4] WRAP Reasonable Progress Source Identification and Analysis Protocol for Second 10-year Regional Haze Implementation Plans, February 27, 2019, Pages 5-6.

The TSPP is 130 km from the nearest Class I area as shown in Figure 1. Total annual emissions of total PM/PM_{10}, SO_2, and NO_X averaged only 500 ton/yr for the 2016 to 2018 period. Therefore, based on 2016-2018 average emissions, Q/d for TSPP is only 4.[5]

3. EPA Guidance on Effectively Controlled Sources

EPA's regional haze guidance[6] includes several criteria that, if applicable, would indicate that a source already has effective controls in place as result of a previous regional haze decision or other Clean Air Act (CAA) requirements and as such, it may be reasonable for the state to not select a particular source for further analysis.[7] In addition, EPA guidance for effectively controlled sources, suggests that a full four-factor analysis would likely result in a conclusion that no additional controls are necessary.

3.1 New Source Performance Standards

EPA regional haze guidance for considering new source performance standards states:

> "New, reconstructed, or modified emission units subject to and complying with New Source Performance Standards (NSPS) that were promulgated or reviewed since July 31, 2013, and that regulate emissions of visibility-impairing pollutants, on a pollutant-specific basis. The statutory considerations for setting NSPS are similar to the four statutory factors for reasonable progress, and it is unlikely that new control measures will be available, or that previously known control measures can be made significantly more effective, beyond those relied on in up-to-date NSPS."

TSPP is subject to the NSPS for fossil fuel fired electric generating units (40 CFR Part 60 Subpart Da). Because construction of the TSPP began in 2005 and the boiler has not had any modification or reconstruction since, TSPP is not subject to any NSPS developed after 2005. There is no post-July 31, 2013 review of Subpart Da emission limits for visibility-impairing pollutants. The most recent revisions to Subpart Da for visibility-impairing pollutants was promulgated in 2012.[8] Although TSPP is not subject to the latest version of Subpart Da, a comparison of TSPP's emissions to the latest Subpart Da emissions standards shows that, if applicable, TSPP emissions would comply with the current Subpart Da requirements.

For units constructed/reconstructed/modified after May 3, 2011, Subpart Da limits filterable PM emissions to 0.09 lb/MWh gross energy output. The data in Table 1 show that TSPP's average actual filterable PM emissions are 0.03 lb/MWh gross energy output.

For units constructed/reconstructed/modified after May 3, 2011, Subpart Da limits SO_2 emissions to 1.0 lb/MWh gross energy output. The data in Table 1 show that TSPP's average actual SO_2 emissions are 0.3 lb/MWh gross energy output.

For units constructed/reconstructed/modified after May 3, 2011, Subpart Da limits NO_X emissions to 0.70 lb/MWh gross energy output. The data in Table 1 show that TSPP's average actual NO_X emissions are 0.49 lb/MWh gross energy output.

[5] Note that other emission sources at the site are material handling operations with total emissions less than 10 ton/yr of PM.
[6] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019.
[7] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019. Page 23
[8] Federal Register, Vol. 77, No. 32, Pages 9304-9510, February 16, 2012.

For units constructed after May 3, 2011, Subpart Da limits SO_2 emissions to 1.0 lb/MWh gross energy output. The data in Table 1 show that TSPP average emissions are 0.3 lb/MWh gross energy output.

For units constructed after May 3, 2011, Subpart Da limits NOx emissions to 0.70 lb/MWh gross energy output. The data in Table 1 show that TSPP average emissions are 0.49 lb/MWh gross energy output.

3.2 Best Available Control Technology

EPA regional haze guidance for Best Available Control Technology states:

> "New, reconstructed, or modified emission units that went through Best Available Control Technology (BACT) review under the Prevention of Significant Deterioration (PSD) program or Lowest Achievable Emission Rate (LAER) review under the nonattainment new source review program for major sources and received a construction permit on or after July 31, 2013, on a pollutant-specific basis. The statutory considerations for selection of BACT and LAER are also similar to, if not more stringent than, the four statutory factors for reasonable progress."

TSPP emission control requirements are based on a 2005 BACT determination. However, as discussed in Section 4, there have been no major technological advancements since that time and the 2005 BACT determinations for TSPP are consistent with post-2005 determinations. Therefore, in accordance with EPA guidance, PM, SO_2, and NO_X emissions are already effectively controlled.

3.3 SO_2 Control Measures

EPA's regional haze guidance for SO_2 control measures states:

> "For the purpose of SO_2 control measures, an EGU that has add-on flue gas desulfurization (FGD) and that meets the applicable alternative SO_2 emission limit of the 2012 Mercury Air Toxics Standards (MATS) rule for power plants. The two limits in the rule (0.2 lb/MMBtu for coal-fired EGUs or 0.3 lb/MMBtu for EGUs fired with oil-derived solid fuel) are low enough that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of SO_2 is necessary to make reasonable progress."

As shown in Table 1, average actual annual SO_2 emissions are 0.03 lb/MMBtu, far below the emission level cited in the MATs rule. Therefore, in accordance with EPA guidance, SO_2 emissions are already effectively controlled.

3.4 National Emission Standards for Hazardous Air Pollutants

EPA's regional haze guidance for sources subject to National Emission Standard for Hazardous Air Pollutants states:

> "For the purpose of PM control measures, a unit that is subject to and complying with any CAA Section 112 National Emission Standard for Hazardous Air Pollutants (NESHAP) or CAA Section 129 solid waste combustion rule, promulgated or reviewed since July 31, 2013, that uses total or filterable PM as a surrogate for metals or has specific emission limits for metals. The NESHAPs are reviewed every 8 years and their emission limits for PM and metals reflects the maximum achievable control technology for major sources and the generally available control technology for area sources. It is

> unlikely that an analysis of control measures for a source subject to, and meeting one of these NESHAPs would conclude that even more stringent control of PM is necessary to make reasonable progress."

TSPP's boiler is subject the Mercury and Air Toxics (MATS) rule (40 CFR Part 63, Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units) as an existing source. The rule limits filterable PM emissions, as a surrogate for metals, to 0.03 lb/MMBtu (0.3 lb/MWh) for existing sources and 0.09 lb/MWh gross energy output for sources constructed/reconstructed after May 3, 2011. TSPP boiler's average filterable PM emissions are 0.003 lb/MMBtu and 0.03 lb/MWh gross energy output, well below the NESHAP standard. Therefore, in accordance with EPA guidance, PM emissions are already effectively controlled.

4. Best Available Control Technology Review

As previously discussed in Section 3.2, since the statutory considerations for selection of BACT are similar to, if not more stringent than the four statutory factors for reasonable progress, if source emissions are consistent with current BACT determinations a four-factor analysis should not be necessary to demonstrate reasonable progress. This can be demonstrated for the TSPP. To do this, data in EPA's RACT/BACT/LAER Clearinghouse (RBLC) for permits issued on May 5, 2005 through November 2019 were reviewed to identify any significant BACT advancements since the TSPP PSD permit was issued.

Emission limits for PM are summarized in Table 2, sorted in descending order from the most recent permit. Emission limits are variable and possibly affected by the type of combustion unit, fuel type, the particulate species and other site-specific factors. For TSPP, the filterable PM/PM_{10} emission limit is 0.012 lb/MMBtu and average actual emissions are 0.0033 lb/MMBtu. Comparison of TSPP emissions to the BACT emission limits in Table 2 show that average actual emissions are lower than recent BACT determinations.

Emission limits for SO_2 are summarized in Table 3, sorted in descending order from the most recent permit. Like PM, SO_2 emission limits are variable and possibly affected by the type of combustion unit, fuel type, and other site-specific factors. For TSPP, the SO_2 emission limit is 0.065 lb/MMBtu[9] as a 30-day average and annual average actual emissions are 0.0031 lb/MMBtu. Comparison of TSPP emissions to the BACT emission limits in Table 3 show that emissions are lower than recent BACT determinations.

Emission limits for NO_X are summarized in Table 4, sorted in descending order from the most recent permit. Emission limits are variable and possibly affected by the type of combustion unit, fuel type, and other site-specific factors. For TSPP, the NO_X emission limit is 0.067 lb/MMBtu and annual average actual emissions 0.051 lb/MMBtu. Comparison of TSPP boiler's NO_X emissions to the BACT emission limits in Table 4 show that emissions are lower than recent BACT determinations.

5. Conclusions

As discussed in the previous sections, TSPP is already a very well controlled coal fired power plant. Comparison of the boiler's current actual emissions to NSPS, NESHAP, MATS and recent BACT determinations shows that the existing emission controls provide for reasonable

[9] The fuel actually burned by TSPP is <0.45% S.

progress for the second planning period of the regional haze rule. In addition, the Q/d for TSPP based on actual 2016 to 2018 emissions is low, only approximately 4, which indicates that any additional emission controls would result in minimal visibility benefits.

Figure 1: TS Power Plant Location and Nearby Class I Areas

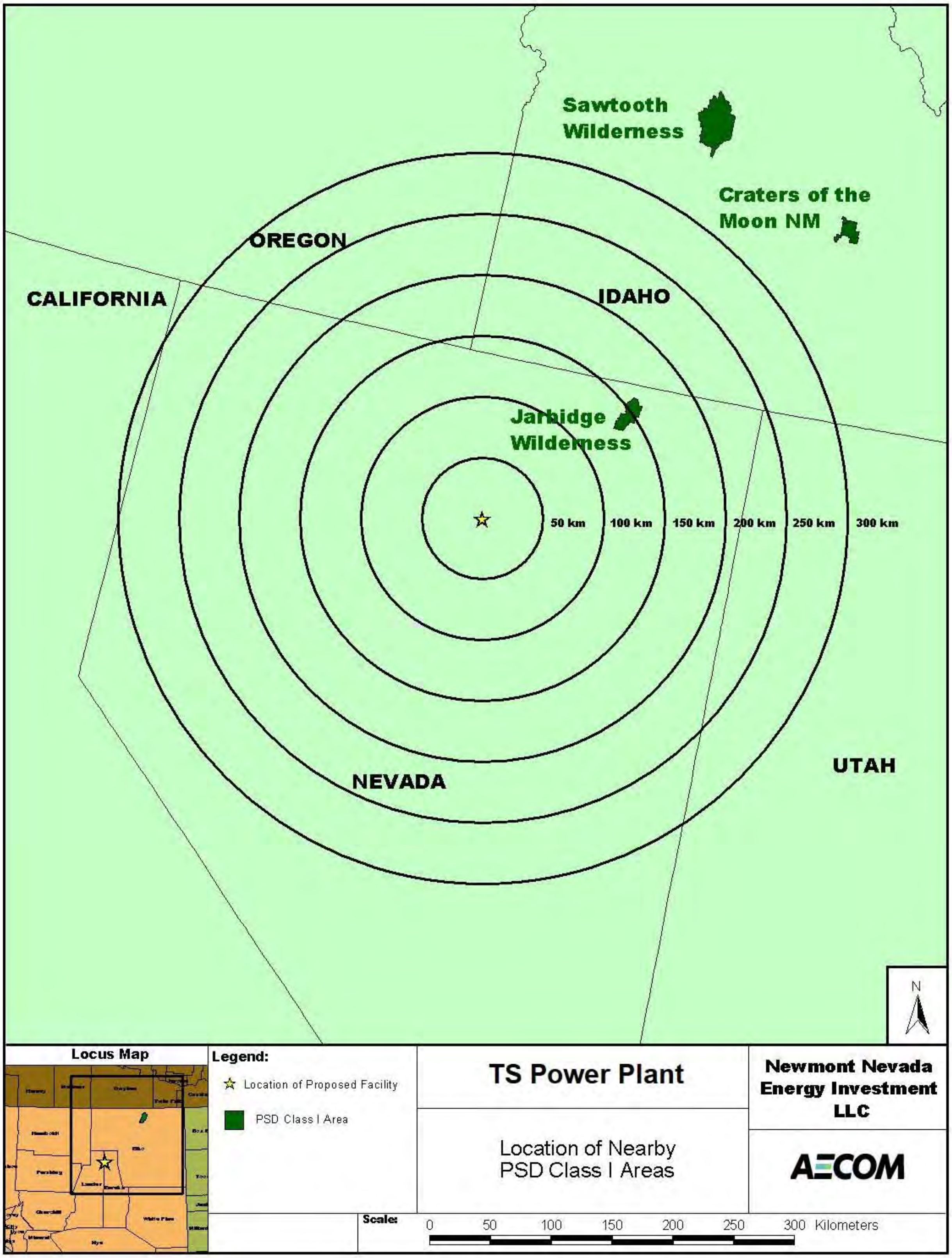
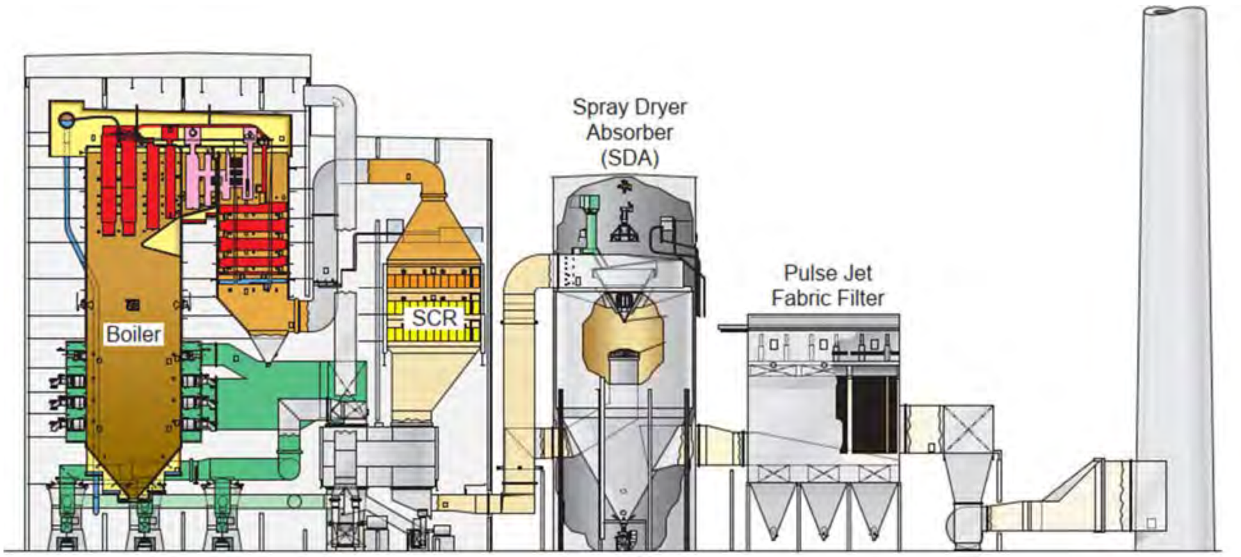


Figure 2: TSPP Side View[10]



.Newmont Mining TS Power Plant

Table 1: TSPP Recent Emissions and Operating Data

	Units	2016-2018 Actual Average		Permit Limit		
		Value	Notes	Value	Averaging Time	Notes
Operating Hours	hr/yr	8,124	EPA Air Markets Program Data (a)	NA	NA	
Power Production	MWh	1,079,600	EPA Air Markets Program Data (a)			
Fuel Use	MMBtu/yr	10,412,437	EPA Air Markets Program Data (a)	21,567,120	NA	Not a permit limit, based on 2,462 MMBtu/hr rated heat input
Fuel Use	MMBtu/hr based on 8,760 hr/yr	1,189	Calculated	2,462	1 hr	
Total PM/PM_{10} (b)	lb/MMBtu	0.0147	3 stack tests, 2016 to 2018	0.176	24 hr	
Total PM/PM_{10} (b)	ton/yr	76.5	Calculated	337.9	12 months	
Filterable PM/PM_{10} (c)	lb/MMBtu	0.00320	3 stack tests, 2016 to 2018	0.012	24 hr	
Filterable PM/PM_{10} (c)	ton/yr	16.7	Calculated	106.7	Annual	
SO_2	lb/MMBtu	0.0309	EPA Air Markets Program Data (a)	0.065	24-rolling average	Requirement applies to 30-day rolling average fuel S <0.45%. Only one 30-day rolling average during this 3-year time period was not <0.45% S.
SO_2	ton/yr	160.7	EPA Air Markets Program Data (a)	800.2	12-month rolling average	
SO_2 Control Efficiency	%	>95%	CEMs Data	91%	30-day rolling average	Requirement applies to 30-day rolling average fuel S <0.45%. Only one 30-day rolling average during this 3-year time period was not <0.45% S.
NOx	lb/MMBtu	0.0505	EPA Air Markets Program Data (a)	0.067	24 hr	
NOx	ton/yr	262.7	EPA Air Markets Program Data (a)	595.7	Annual	

(a) EPA Air Markets Program Data https://ampd.epa.gov/ampd/
(b) EPA Methods 5 and 202. All PM assumed to be PM10.
(c) EPA Method 5. All PM assumed to be PM10.

Table 2: EPA RBLC Results for PM Emissions

RBLCID	Facility Name	Permit Issuance Date	Process Name	Primary Fuel	Throughput		Pollutant		Emission Limit		Emission Limit Avg Time Condition	Case-by-Case Basis
TX-0700	LIMESTONE ELECTRIC GENERATING STATION	12/20/2013	(2) coal-fired boilers	PRB coal	900	MW	Particulate matter, total (TPM_{10})	Electrostatic Precipitators and Wet Flue Gas Desulfurization	0.0300	lb/MMBtu		BACT-PSD
TX-0700	LIMESTONE ELECTRIC GENERATING STATION	12/20/2013	(2) coal-fired boilers	PRB coal	900	MW	Particulate matter, total ($TPM_{2.5}$)	Electrostatic Precipitators and Wet Flue Gas Desulfurization	0.0300	lb/MMBtu		BACT-PSD
TX-0700	LIMESTONE ELECTRIC GENERATING STATION	12/20/2013	(2) coal-fired boilers	PRB coal	900	MW	Particulate matter, total (TPM)	Electrostatic Precipitators and Wet Flue Gas Desulfurization	0.0300	lb/MMBtu		BACT-PSD
WY-0073	JIM BRIDGER POWER PLANT	6/17/2013	Unit 4	Coal	6,000	MMBtu	Particulate matter, total ($TPM_{2.5}$)	Utilize existing WFGD and ESP	0.0180	lb/MMBtu	3-HR AVERAGE	BACT-PSD
WY-0073	JIM BRIDGER POWER PLANT	6/17/2013	Unit 3	Coal	6,000	MMBTU/H	Particulate matter, total ($TPM_{2.5}$)	Utilize existing WFGD and ESP	0.0205	lb/MMBtu	3-HR AVERAGE	BACT-PSD
WY-0073	JIM BRIDGER POWER PLANT	6/17/2013	Unit 4	Coal	6,000	MMBtu	Particulate matter, total (TPM_{10})	Utilize existing WFGD and ESP	0.0397	lb/MMBtu	3-HR AVERAGE	BACT-PSD
WY-0073	JIM BRIDGER POWER PLANT	6/17/2013	Unit 3	Coal	6,000	MMBTU/H	Particulate matter, total (TPM_{10})	Utilize existing WFGD and ESP	0.0418	lb/MMBtu	3-HR AVERAGE	BACT-PSD
MI-0400	WOLVERINE POWER	6/29/2011	Circulating Fluidized Bed Boilers	Petcoke and coal	3,030	MMBTU/H EACH	Particulate matter, filterable (FPM)	Pulse jet fabric filter	0.0100	lb/MMBtu	EACH; TEST PROTOCOL	BACT-PSD
MI-0400	WOLVERINE POWER	6/29/2011	CFB boiler	Petcoke/coal	3,030	MMBTU/H EACH	Particulate matter, total ($TPM_{2.5}$)	Pulse jet fabric filter	0.0180	lb/MMBtu	EACH; BACT & SIP; SS ONLY	BACT-PSD
MI-0400	WOLVERINE POWER	6/29/2011	CFB boiler	Petcoke/coal	3,030	MMBTU/H each	Particulate matter, total ($TPM_{2.5}$)	Pulse jet Fabric filter	0.0240	lb/MMBtu	EACH; TEST PROTOCOL; BACT&SIP	BACT-PSD
MI-0400	WOLVERINE POWER	6/29/2011	CFB boiler	Petcoke and coal	3,030	MMBTU/H EACH	Particulate matter, total ($TPM_{2.5}$)	Pulse jet fabric filter	0.0240	lb/MMBtu	EACH; TEST PROTOCOL; BACT	BACT-PSD
MI-0400	WOLVERINE POWER	6/29/2011	CFB boiler	Petcoke and coal	3,030	MMBTU/H EACH	Particulate matter, total (TPM_{10})	Pulset jet fabric filter	0.0260	lb/MMBtu	EACH; TEST PROTOCOL	BACT-PSD
MI-0403	HOLLAND BOARD OF PUBLIC WORKS-JAMES DEYOUNG PLANT	2/11/2011	CFB boiler	sub&bit coal	865	MMBTU/H	Particulate matter, filterable (FPM)	Fabric filter and fugitive dust control plan	0.0100	lb/MMBtu	TEST PROTOCOL	BACT-PSD
MI-0403	HOLLAND BOARD OF PUBLIC WORKS-JAMES DEYOUNG PLANT	2/11/2011	CFB boiler	sub&bit coal	865	MMBTU/H	Particulate matter, total (TPM_{10})	Fabric filter and fugitive dust control plan	0.0250	lb/MMBtu	TEST PROTOCOL WILL SPECIFY AVG TIME.	BACT-PSD

Table 2: EPA RBLC Results for PM Emissions

RBLCID	Facility Name	Permit Issuance Date	Process Name	Primary Fuel	Throughput		Pollutant		Emission Limit		Emission Limit Avg Time Condition	Case-by-Case Basis
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	12/30/2010	Coal-fired Boiler	Sub-bituminous coal	8,307	MMBTU/H	Particulate matter, filterable (FPM_{10})	Fabric Filter	0.0120	lb/MMBtu	12-MONTH ROLLING AVG	BACT-PSD
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	12/30/2010	Coal-fired Boiler	Sub-bituminous coal	8,307	MMBTU/H	Particulate matter, total (TPM_{10})	Fabric filter and wet scrubber	0.0250	lb/MMBtu	12-MONTH ROLLING AVG	BACT-PSD
MI-0399	DETROIT EDISON--MONROE	12/21/2010	Boiler Units 1, 2, 3 and 4	Coal	7,624	MMBTU/H	Particulate matter, filterable (FPM)	ESPs and wet flue gas desulfurization.	0.0110	lb/MMBtu	EACH, TEST/ OR 24H ROLL.AVG. IF PM CEMS	BACT-PSD
MI-0399	DETROIT EDISON--MONROE	12/21/2010	Boiler Units 1, 2, 3 and 4	Coal	7,624	MMBTU/H	Particulate matter, total (TPM_{10})	ESPs and wet flue gas desulfurization.	0.0240	lb/MMBtu	EACH, TEST	BACT-PSD
TX-0577	WHITE STALLION ENERGY CENTER	12/16/2010	CFB BOILER	COAL & PET COKE	3,300	MMBTU/H	Particulate matter, filterable (FPM)	BAGHOUSE	0.0100	lb/MMBtu	3-HR	BACT-PSD
TX-0577	WHITE STALLION ENERGY CENTER	12/16/2010	CFB BOILER	COAL & PET COKE	3,300	MMBTU/H	Particulate matter, total (TPM)	LSD, ACTIVATED CARBON, BAGHOUSE	0.0180	lb/MMBtu	3-HR COAL	BACT-PSD
TX-0554	COLETO CREEK UNIT 2	5/3/2010	Coal-fired Boiler Unit 2	PRB coal	6,670	MMBTU/H	Particulate matter, filterable (FPM_{10})	fabric filter	0.0120	lb/MMBtu	ANNUAL / BASED ON STACK TEST	BACT-PSD
TX-0554	COLETO CREEK UNIT 2	5/3/2010	Coal-fired Boiler Unit 2	PRB coal	6,670	MMBTU/H	Particulate matter, total (TPM)	fabric filter, spray dry adsorber for acid gases	0.0250	lb/MMBtu	ANNUAL / STACK TEST	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	4/9/2010	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	COAL	3,000	MMBTU/H	Particulate matter, filterable (FPM_{10})	BAGHOUSE	0.0900	lb/MMBtu		BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	4/9/2010	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	COAL	3,000	MMBTU/H	Particulate matter, filterable (FPM)	BAGHOUSE	0.0900	lb/MMBtu	30 DAY AVERAGE	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009	BOILER	PRB COAL OR 50/50 BLEND	8,190	MMBTU/H	Particulate matter, filterable (FPM)	FABRIC FILTER	0.0110	lb/MMBtu	TEST METHOD	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009	BOILER	PRB COAL OR 50/50 BLEND	8,190	MMBTU/H	Particulate matter, total (TPM_{10})	FABRIC FILTER, HYDRATED LIME INJECTION	0.0240	lb/MMBtu	TEST METHOD	BACT-PSD
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/8/2009	BOILER (2), PULVERIZED COAL FIRED	PULVERIZED COAL	5,191	MMBTU/H	Particulate matter, filterable (FPM)	BAGHOUSE IN COMBINATION WITH A WET ELECTROSTATIC PRECIPITATOR (WESP)	0.0120	lb/MMBtu	HEAT INPUT, AS 3-HR AVERAGE	MACT
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/8/2009	BOILER (2), PULVERIZED COAL FIRED	PULVERIZED COAL	5,191	MMBTU/H	Particulate matter, filterable (FPM_{10})	BAGHOUSE IN COMBINATION WITH A WET ELECTROSTATIC PRECIPITATOR (WESP)	0.0241	lb/MMBtu	AS 3-HR AVERAGE EACH BOILER	BACT-PSD
AZ-0050	CORONADO GENERATING STATION	1/22/2009	UNIT 1	COAL	4,719	MMBTU/H	Particulate matter, filterable (FPM_{10})	ESP	0.0300	lb/MMBtu	3-HOURS	BACT-PSD
AZ-0050	CORONADO GENERATING STATION	1/22/2009	UNIT 2	COAL	4,719	MMBTU	Particulate matter, filterable (FPM_{10})	ESP	0.0300	lb/MMBtu	3-HOUR AVG	BACT-PSD

Table 2: EPA RBLC Results for PM Emissions

RBLCID	Facility Name	Permit Issuance Date	Process Name	Primary Fuel	Throughput		Pollutant		Emission Limit		Emission Limit Avg Time Condition	Case-by-Case Basis
AR-0094	JOHN W. TURK JR. POWER PLANT	11/5/2008	PC BOILER	PRB SUB-BIT COAL	6,000	MMBTU/H	Particulate matter, filterable (FPM_{10})	FABRIC FILTER	0.0120	lb/MMBtu	3 HOUR AVERAGE	BACT-PSD
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	6/30/2008	2 CIRCULATING FLUIDIZED BED BOILERS	COAL AND COAL REFUSE	3,132	MMBTU/H	Particulate matter, filterable (FPM)	GOOD COMBUSTIONS PRACTICES AND BAGHOUSE	0.0100	lb/MMBtu	3 HOURS	BACT-PSD
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	6/30/2008	2 CIRCULATING FLUIDIZED BED BOILERS	COAL AND COAL REFUSE	3,132	MMBTU/H	Particulate matter, total (TPM_{10})	GOOD COMBUSTION PRACTICES AND BAGHOUSE	0.0120	lb/MMBtu	3 HOURS	BACT-PSD
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	6/30/2008	2 CIRCULATING FLUIDIZED BED BOILERS	COAL AND COAL REFUSE	3,132	MMBTU/H	Particulate matter, total ($TPM_{2.5}$)	GOOD COMBUSTION PRACTICES AND BAGHOUSE	0.0120	lb/MMBtu	3 HOURS	BACT-PSD
MO-0077	NORBORNE POWER PLANT	2/22/2008	MAIN BOILER	COAL	#######	T/YR	Particulate matter, filterable (FPM_{10})	FABRIC FILTRATION SYSTEM (BAGHOUSE)	0.0180	lb/MMBtu	3 HOURS ROLLING AVERAGE (TOTAL PAM10)	BACT-PSD
WY-0064	DRY FORK STATION	10/15/2007	PC BOILER (ES1-01)	COAL			Particulate matter, filterable (FPM_{10})	FABRIC FILTER (BAGHOUSE)	0.0120	lb/MMBtu	ANNUAL	BACT-PSD
ND-0024	SPIRITWOOD STATION	9/14/2007	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	LIGNITE	1,280	MMBTU/H	Particulate matter, filterable (FPM_{10})	BAGHOUSE	0.0120	lb/MMBtu	3 H	BACT-PSD
ND-0024	SPIRITWOOD STATION	9/14/2007	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	LIGNITE	1,280	MMBTU/H	Particulate matter, filterable (FPM)	BAGHOUSE	0.0150	lb/MMBtu	3 H	BACT-PSD
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	8/30/2007	CIRCULATING FLUIDIZED BED BOILER	WASTE COAL/BITUMIN OUS BLEND	1,445	MMBTU/H	Particulate matter, filterable (FPM10)	PULSE-JET FABRIC FILTER BAGHOUSE	0.0120	lb/MMBtu	24-HOUR BLOCK AVERAGE	BACT-PSD
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	8/30/2007	CIRCULATING FLUIDIZED BED BOILER	WASTE COAL/BITUMIN OUS BLEND	1,445	MMBTU/H	Particulate matter, filterable (FPM)	PULSE-JET FABRIC FILTER BAGHOUSE	0.0120	lb/MMBtu	24-HOUR BLOCK AVERAGE	BACT-PSD
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	8/30/2007	CIRCULATING FLUIDIZED BED BOILER	WASTE COAL/BITUMIN OUS BLEND	1,445	MMBTU/H	Particulate Matter (PM)	PULSE-JET FABRIC FILTER BAGHOUSE	0.0300	lb/MMBtu	24-HOUR BLOCK AVERAGE (12 AM TO 12 AM)	BACT-PSD
FL-0295	CRYSTAL RIVER POWER PLANT	5/18/2007	FFFSG UNITS 4 AND 5	COAL	760	MW	Particulate matter, filterable (FPM10)	MODIFIED ESP (IMPROVEMENTS)	0.0300	lb/MMBtu		BACT-PSD
CO-0072	CRAIG ELECTRIC GENERATING STATION	5/16/2007	Unit 3 Coal boiler	coal	4,600	MMBTU/H	Particulate matter, filterable (FPM10)	Baghouse	0.0120	lb/MMBtu	AVE OVER STACK TEST LENGTH	BACT-PSD
CO-0072	CRAIG ELECTRIC GENERATING STATION	5/16/2007	Unit 3 Coal boiler	coal	4,600	MMBTU/H	Particulate matter, filterable (FPM)	Baghouse	0.0130	lb/MMBtu	AVE OVER STACK TEST LENGTH	BACT-PSD
CO-0072	CRAIG ELECTRIC GENERATING STATION	5/16/2007	Unit 3 Coal boiler	coal	4,600	MMBTU/H	Particulate matter, total (TPM_{10})	Baghouse	0.0200	lb/MMBtu	AVE OVER STACK TEST LENGTH	BACT-PSD
CO-0072	CRAIG ELECTRIC GENERATING STATION	5/16/2007	Unit 3 Coal boiler	coal	4,600	MMBTU/H	Particulate matter, total (TPM)	Baghouse	0.0220	lb/MMBtu	AVE OVER STACK TEST LENGTH	BACT-PSD

Table 2: EPA RBLC Results for PM Emissions

RBLCID	Facility Name	Permit Issuance Date	Process Name	Primary Fuel	Throughput		Pollutant		Emission Limit		Emission Limit Avg Time Condition	Case-by-Case Basis
PA-0257	SUNNYSIDE ETHANOL, LLC	5/7/2007	CFB BOILER	COAL	497	MMBTU/H	Particulate matter, filterable (FPM_{10})	CYCLONE AND BAGHOUSE	0.0100	lb/MMBtu	FILTERABLE	BACT-PSD
OK-0118	HUGO GENERATING STA	2/9/2007	COAL-FIRED STEAM EGU BOILER		750	MW	Particulate matter, filterable (FPM_{10})	FABRIC FILTER BAGHOUSE	0.0150	lb/MMBtu	FILTERABLE	BACT-PSD
WY-0063	WYGEN 3	2/5/2007	PC BOILER	SUBBITUMINOUS COAL	1,300	MMBTU/H	Particulate matter, filterable (FPM)	BAGHOUSE	0.0120	lb/MMBtu	3 X 120 MINUTE TEST	BACT-PSD
TX-0491	MEADWESTVACO TEXAS LP PULP AND PAPER MILL	1/24/2007	NO. 6 POWER BOILER	SCRAP WOOD AND BARK			Particulate matter, filterable (FPM_{10})	VENTURI WET SCRUBBER	0.1000	lb/MMBtu		BACT-PSD
IL-0107	DALLMAN POWER PLANT	8/10/2006	DALLMAN 4 ELECTRICAL GENERATING UNIT				Particulate matter, filterable (FPM)	CONVENTIONAL DRY ESP FOLLOWED BY WET ESP.	0.0120	lb/MMBtu	3-HOUR BLOCK AVERAGE	BACT-PSD
IL-0107	DALLMAN POWER PLANT	8/10/2006	DALLMAN 4 ELECTRICAL GENERATING UNIT				Particulate Matter (PM)	CONVENTIONAL DRY ESP, CONVENTIONAL SCRUBBER AND WET ESP.	0.0350	lb/MMBtu	3-HOUR BLOCK AVERAGE	BACT-PSD
TX-0499	SANDY CREEK ENERGY STATION	7/24/2006	PULVERIZED CAOL BOILER	COAL	8,185	MMBTU/H	Particulate matter, filterable (FPM_{10})		0.0150	lb/MMBtu	1-HR	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	4/26/2006	CIRCULATING FLUIDIZED BED BOILER (CFB)	WASTE COAL	1,070	mmbtu/h	Particulate matter, filterable (FPM)	BAGHOUSE	0.0150	lb/MMBtu	30-DAY	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	4/26/2006	CIRCULATING FLUIDIZED BED BOILER (CFB)	WASTE COAL	1,070	mmbtu/h	Particulate Matter (PM)	BAGHOUSE	0.0300	lb/MMBtu	30-DAY	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	4/26/2006	CIRCULATING FLUIDIZED BED BOILER (CFB)	WASTE COAL	1,070	mmbtu/h	Particulate matter, filterable (FPM_{10})	BAGHOUSE	0.0300	lb/MMBtu	30-DAY	BACT-PSD
CO-0055	LAMAR LIGHT & POWER POWER PLANT	2/3/2006	CIRCULATING FLUIDIZED BED BOILER	COAL COAL (BITUMINOUS/ SUBBITUMINOUS)	502	MMBTU/H	Particulate matter, filterable (FPM_{10})	HIGH EFFICIENCY(MEMBRANE) LINED FABRIC FILTER BAGHAUSE FOR FILTEARABLE PARTICULATE MATTER	0.0120	lb/MMBtu	DURATION OF TESTS	BACT-PSD
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	1/27/2006	PULVERIZED COAL BOILER - UNIT 2	PULVERIZED COAL	4,000	T/H	Particulate matter, filterable (FPM10)	FABRIC FILTRATION SYSTEM (BAGHOUSE)	0.0236	lb/MMBtu	30 DAYS ROLLING AVERAGE FILTABLE/COND.	BACT-PSD
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	1/27/2006	PULVERIZED COAL BOILER - UNIT 1	COAL	4,000	T/H	Particulate matter, filterable (FPM_{10})	BAGHOUSE	0.0244	lb/MMBtu	30 DAYS ROLLING AVERAGE	BACT-PSD
LA-0176	BIG CAJUN II POWER PLANT	8/22/2005	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	SUBBITUMINOUS COAL	#######	T/YR	Particulate matter, filterable (FPM_{10})	ESP AND BAGHOUSE IN SERIES CONFIGURATION	0.0300	lb/MMBtu	ANNUAL AVERAGE	BACT-PSD

Table 2: EPA RBLC Results for PM Emissions

RBLCID	Facility Name	Permit Issuance Date	Process Name	Primary Fuel	Throughput		Pollutant		Emission Limit		Emission Limit Avg Time Condition	Case-by-Case Basis
PA-0249	RIVER HILL POWER COMPANY, LLC	7/21/2005	CFB BOILER	WASTE COAL			Particulate matter, filterable (FPM_{10})	BAGHOUSE	0.0100	lb/MMBtu	12 MONTH ROLLING AVERAGE	BACT-PSD
PA-0248	GREENE ENERGY RESOURCE RECOVERY PROJECT	7/8/2005	2 CFB BOILERS	WASTE COAL	358	T/H (each)	Particulate matter, filterable (FPM_{10})	BAGHOUSE, EPA METHODS 201,201A,202. PROVISION TO INCREASE IF CAN'T MEET LIMIT BECAUSE OF CONDENSIBLES PER METHOD 202	0.0120	lb/MMBtu		BACT-PSD
CO-0057	COMANCHE STATION	7/5/2005	PC BOILER - UNIT 3	SUB-BITUMINOUS COAL	7,421	MMBTU/H	Particulate matter, filterable (FPM_{10})	BAGHOUSE	0.0120	lb/MMBtu	FILTERABLE, AVG OF 3 TEST RUNS	BACT-PSD
CO-0057	COMANCHE STATION	7/5/2005	PC BOILER - UNIT 3	SUB-BITUMINOUS COAL	7,421	MMBTU/H	Particulate Matter (PM)	BAGHOUSE	0.0130	lb/MMBtu	FILTERABLE, AVG OF 3 TEST RUNS	BACT-PSD
ND-0021	GASCOYNE GENERATING STATION	6/3/2005	BOILER, COAL-FIRED	LIGNITE	2,116	MMBTU/H	Particulate matter, filterable (FPM_{10})	BAGHOUSE	0.0130	lb/MMBtu	3-H	BACT-PSD
ND-0021	GASCOYNE GENERATING STATION	6/3/2005	BOILER, COAL-FIRED	LIGNITE	2,116	MMBTU/H	Particulate Matter (PM)	BAGHOUSE	0.0167	lb/MMBtu	3-H	BACT-PSD
NV-0036	TS POWER PLANT	5/5/2005	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	2,030	MMBTU/H	Particulate matter, filterable (FPM_{10})	FABRIC FILTER DUST COLLECTION	0.0120	lb/MMBtu	24-HOUR ROLLING - FILTERABLE ONLY	BACT-PSD

Table 3: EPA RBLC Results for SO_2 Emissions

RBLCID	Facility Name	Permit Issuance Date	PROCESS Name	PRIMARY FUEL	THROUGHPUT		CONTROL METHOD DESCRIPTION	Emission Limit		EMISSION LIMIT AVG TIME CONDITION	CASE BY CASE BASIS
TX-0601	GIBBONS CREEK STEAM ELECTRIC STATION	10/28/2011	Boiler	Coal	5,060	MMBtu/h	Wet Flue Gas Desulfurization	1.200	lb/MMBtu		BACT-PSD
CA-1206	STOCKTON COGEN COMPANY	9/16/2011	CIRCULATING FLUIDIZED BED BOILER	COAL	730	MMBTU/H	LIMESTONE INJECTION W/ A MINIMUM REMOVAL EFFICIENCY OF 70% (3-HR AVG) TO BE MAINTAINED AT ALL TIMES	0.081	lb/MMBtu	8-HR AVG	BACT-PSD
MI-0400	WOLVERINE POWER	6/29/2011	Circulating Fluidized Bed Boilers	Petcoke/coal	3,030	MMBTU/H EACH	Dry flue gas desulfurization (spray dry absorber or polishing scrubber).	0.100	lb/MMBtu	EACH; 24-H ROLL.AVG.; BACT & SIP	BACT-PSD
MI-0400	WOLVERINE POWER	6/29/2011	Circulating Fluidized Bed Boilers	Petcoke/coal	3,030	MMBTU/H each	Dry flue gas desulfurization (spray dry absorber or polishing scrubber).	0.060	lb/MMBtu	EACH; 30D ROLL.AVG.; BACT&SIP; EXC. SS	BACT-PSD
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	12/30/2010	Coal-fired Boiler	Sub-bituminous coal	8,307	MMBTU/H	Wet limestone scrubber	0.060	lb/MMBtu	30-DAY ROLLING	BACT-PSD
MI-0399	DETROIT EDISON--MONROE	12/21/2010	Boiler Units 1, 2, 3 and 4	Coal	7,624	MMBTU/H	Wet flue gas desulfurization.	0.107	lb/MMBtu	EACH, 24-H ROLL. AVG.	BACT-PSD
TX-0577	WHITE STALLION ENERGY CENTER	12/16/2010	CFB BOILER	COAL & PET COKE	3,300	MMBTU/H	LIMESTONE BED CFB AND LIME SPRAY DRYER PERMIT DESIGN SULFUR CONTENT OF ILL BASIN COAL IS 3.9 WT% AND OF PET COKE 4.3 AVG/6.0 MAX	0.114	lb/MMBtu	PET COKE 30-DAY ROLLING	BACT-PSD
TX-0554	COLETO CREEK UNIT 2	5/3/2010	Coal-fired Boiler Unit 2	PRB coal	6,670	MMBTU/H	Spray Dry Adsorber/Fabric Filter	0.060	lb/MMBtu	30-DAY ROLLING	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	4/9/2010	CIRCULATING FLUIDIZED BED BOILER	COAL	3,000	MMBTU/H	LIMESTONE INJECTION (CFB)AND A FLASH DRYER ABSORBER WITH FRESH LIME INJECTION	0.075	lb/MMBtu	30 DAY AVERAGE	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009	BOILER	PRB COAL OR 50/50 BLEND	8,190	MMBTU/H	LIMESTONE FORCED OXIDATION, WET FLUIDIZED GAS DESULFURIZATION (FGD) AND LOW SULFUR COAL.	0.060	lb/MMBtu	30-DAY ROLLING	BACT-PSD
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	10/8/2009	BOILER (2), PULVERIZED COAL FIRED	PULVERIZED COAL	5,191	MMBTU/H	WET FLUE GAS DESULFURIZATION (FGS) EITHER LIME OR AMMONIA-BASED	0.150	lb/MMBtu	AS 3-HR AVERAGE EACH BOILER	BACT-PSD
AR-0094	JOHN W. TURK JR. POWER PLANT	11/5/2008	PC BOILER	PRB SUB-BIT COAL	6,000	MMBTU/H	DRY FLUE GAS DESULFURIZATION (SPRAY DRY ADSORBER)	0.080	lb/MMBtu	30 DAY AVERAGE	BACT-PSD
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	6/30/2008	2 CIRCULATING FLUIDIZED BED BOILERS	COAL AND COAL REFUSE	3,132	MMBTU/H	LIMESTONE INJECTION AND FLUE GAS DESULFURIZATION AND CEM SYSTEM	0.035	lb/MMBtu	3 HOURS	BACT-PSD
WY-0064	DRY FORK STATION	10/15/2007	PC BOILER (ES1-01)	COAL			CIRCULATING DRY SCRUBBER	0.070	lb/MMBtu	12 MONTH ROLLING	BACT-PSD
ND-0024	SPIRITWOOD STATION	9/14/2007	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	LIGNITE	1,280	MMBTU/H	LIMESTONE INJECTION INTO THE UNIT WITH A SPRAY DRYER FOLLOWING.	0.060	lb/MMBtu	30 D ROLLING	BACT-PSD

Table 3: EPA RBLC Results for SO_2 Emissions

RBLCID	Facility Name	Permit Issuance Date	PROCESS Name	PRIMARY FUEL	THROUGHPUT		CONTROL METHOD DESCRIPTION	Emission Limit		EMISSION LIMIT AVG TIME CONDITION	CASE BY CASE BASIS
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	8/30/2007	CIRCULATING FLUIDIZED BED BOILER	WASTE COAL/BITUMINOUS BLEND	1,445	MMBTU/H	LIMESTONE INJECTION SYSTEM DRY SO2 SCRUBBER (SPRAY DRY ABSORBER)	0.055	lb/MMBtu	30-DAY ROLLING	BACT-PSD
PA-0257	SUNNYSIDE ETHANOL, LLC	5/7/2007	CFB BOILER	COAL	497	MMBTU/H	LIMESTONE INJECTION AND ADD ON DRY FLUE GAS DESULFEDRIZATION, CEM	0.200	lb/MMBtu	30 DAY ROLLING AVERAGE	BACT-PSD
IA-0091	OTTUMWA GENERATING STATION	2/27/2007	BOILER #1	COAL	6,370	MMBTU/H	LOW SULFUR COAL	1.200	lb/MMBtu	3-HOUR ROLLING AVERAGE	BACT-PSD
OK-0118	HUGO GENERATING STA	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)		750	MW	WET LIMESTONE FLUE GAS DESULFURIZATION	0.065	lb/MMBtu	30 DAY ROLLING AVERAGE	BACT-PSD
WY-0063	WYGEN 3	2/5/2007	PC BOILER	SUBBITUMINOUS COAL	1,300	MMBTU/H	DRY FGD	0.090	lb/MMBtu	12 MONTH ROLLING	BACT-PSD
TX-0499	SANDY CREEK ENERGY STATION	7/24/2006	PULVERIZED CAOL BOILER	COAL	8,185	MMBTU/H		0.120	lb/MMBtu	30-DAY	BACT-PSD
WV-0024	WESTERN GREENBRIER CO-GENERATION LLC	4/26/2006	CIRCULATING FLUIDIZED BED BOILER (CFB)	WASTE COAL	1,070	mmbtu/h	LIME INJECTION AND FLASH DRYER ABSORBER (FDA)	0.140	lb/MMBtu	3-HOUR	BACT-PSD
CO-0055	LAMAR LIGHT & POWER POWER PLANT	2/3/2006	CIRCULATING FLUIDIZED BED BOILER	COAL (BITUMINOUS/SUB-BITUMINOUS)	502	MMBTU/H	LIMESTONE INJECTION FOR S02 CONTROL	0.103	lb/MMBtu	DAILY AVERAGE	BACT-PSD
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	1/27/2006	PULVERIZED COAL BOILER	PULVERIZED COAL	4,000	T/H	WET SCRUBBER TO REDUCE SOX EMISSIONS. CONTROLS ARE NOT BACT FOR SOX	0.090	lb/MMBtu	30 DAYS ROLLING AVERAGE	BACT-PSD
LA-0176	BIG CAJUN II POWER PLANT	8/22/2005	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	SUBBITUMINOUS COAL	3,518,791	T/YR	OPTION 1: SEMI-DRY LIME SCRUBBER OPTION 2: WET FLUE GAS DESULFURIZATION SYSTEM	0.100	LB/MMBTU	ANNUAL AVERAGE	BACT-PSD
PA-0249	RIVER HILL POWER COMPANY, LLC	7/21/2005	CFB BOILER	WASTE COAL			DRY FLUE GAS DESULFURIZATION SYSYTEM	0.274	lb/MMBtu	24-HR ROLLING AVERAGE	BACT-PSD
PA-0248	GREENE ENERGY RESOURCE RECOVERY PROJECT	7/8/2005	2 CFB BOILERS	WASTE COAL	358	T/H (each)	LIMESTONE INJECTION PLUS A DRY POLISHING SCRUBBER	0.156	lb/MMBtu	30 DAY ROLLING AVE AVERAGE	BACT-PSD
ND-0021	GASCOYNE GENERATING STATION	6/3/2005	BOILER, COAL-FIRED	LIGNITE	2,116	MMBTU/H	LIMESTONE INJECTION WITH A SPRAY DRYER.	0.038	lb/MMBtu	30 DAY ROLLING AVE AVERAGE	BACT-PSD
NV-0036	TS POWER PLANT	5/5/2005	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	2,030	MMBTU/H	LIME SPRAY DRY SCRUBBER	0.065	lb/MMBtu	24-HOUR ROLLING; For COAL SULFUR <0.45%	BACT-PSD

Table 4: EPA RBLC Results for NOx Emissions

RBLCID	Facility Name	Permit Issuance Date	PROCESS Name	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	CONTROL_METHOD_DESCRIPTION	Emission Limit	EMISSION LIMIT UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE_BASIS
OK-0152	MUSKOGEE GENERATING STATION	1/30/2013	COAL-FIRED BOILER	COAL	550	MW	LOW-NOx BURNERS AND OVERFIRE AIR	0.150	lb/MMBtu	30-DAY AVG	BART
OK-0151	SOONER GENERATING STATION	1/17/2013	COAL-FIRED BOILERS	COAL	550	MW	LOW-NOx BURNERS AND OVERFIRE AIR.	0.150	lb/MMBtu	30-DAY AVG	BART
ND-0026	M.R. YOUNG STATION	3/8/2012	Cyclone Boilers, Unit	Lignite	6300	MMBTU/H	SNCR plus separated over fire air	0.350	lb/MMBtu	30 DAY ROLLING AVERAGE	BACT-PSD
AZ-0055	NAVAJO GENERATING STATION	2/6/2012	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.240	lb/MMBtu	30-DAY ROLLING AVG	BACT-PSD
AZ-0055	NAVAJO GENERATING STATION	2/6/2012	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM,	0.240	lb/MMBtu	30-DAY ROLLING AVG	BACT-PSD
MI-0400	WOLVERINE POWER	6/29/2011	Circulating Fluidized Bed Boilers	Petcoke/coal	3030	MMBTU/H each	SNCR (Selective Non-Catalytic Reduction)	0.070	lb/MMBtu	EACH, 30 D ROLLING AVG; BACT	BACT-PSD
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	12/30/2010	Coal-fired Boiler	Sub-bituminous coal	8307	MMBTU/H	Selective Catalytic Reduction	0.050	lb/MMBtu	12-MONTH ROLLING	BACT-PSD
MI-0399	DETROIT EDISON--MONROE	12/21/2010	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Staged combustion, low-NOx burners, overfire air, and SCR.	0.080	lb/MMBtu	EACH, 12-MONTH ROLLING AVG.	BACT-PSD
TX-0577	WHITE STALLION ENERGY CENTER	12/16/2010	CFB BOILER	COAL & PET COKE	3300	MMBTU/H	CFB AND SNCR	0.070	lb/MMBtu	30-DAY ROLLING	BACT-PSD
TX-0554	COLETO CREEK UNIT 2	5/3/2010	Coal-fired Boiler Unit 2	PRB coal	6670	MMBTU/H	low-NOx burners with OFA, Selective Catalytic Reduction	0.060	lb/MMBtu	ROLLING 30 DAY AVG	BACT-PSD
KY-0100	J.K. SMITH GENERATING STATION	4/9/2010	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	COAL	3000	MMBTU/H	SNCR	0.070	lb/MMBtu	30 DAY AVERAGE	BACT-PSD
MI-0389	KARN WEADOCK GENERATING COMPLEX	12/29/2009	BOILER	PRB COAL OR 50/50 BLEND	8190	MMBTU/H	LOW NOX BURNER, OVER-FIRED AIR, SELECTIVE CATALYTIC REDUCTION.	0.050	lb/MMBtu	30-DAY ROLLING	BACT-PSD
NE-0049	OPPD NEBRASKA CITY STATION	2/26/2009	NCS UNIT 1	POWDER RIVER BASIN COAL	370	T/YR	LNB W/OVERFIRE AIR PORT SYSTEM	0.230	lb/MMBtu	30-DAY ROLLING AV	BACT-PSD
AR-0094	JOHN W. TURK JR. POWER PLANT	11/5/2008	PC BOILER	PRB SUB-BIT COAL	6000	MMBTU/H	SELECTIVE CATALYTIC REDUCTION (SCR)	0.067	lb/MMBtu	24 HOUR ROLLING	BACT-PSD
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	6/30/2008	2 CIRCULATING FLUIDIZED BED BOILERS	COAL AND COAL REFUSE	3132	MMBTU/H	SELECTIVE NON-CATALYTIC REDUCTION AND GOOD COMBUSTION PRACTICES AND CEM SYSTEM	0.070	lb/MMBtu	30 DAY ROLLING AVERAGE	BACT-PSD
MO-0077	NORBORNE POWER PLANT	2/22/2008	MAIN BOILER	COAL	3762420	T/YR	SCR - SELECTIVE CATALYTIC REDUCTION LNB - LOW NOX BURNERS OFA - OVERFIRE AIR	0.065	lb/MMBtu	30 DAYS ROLLING AVERAGE	BACT-PSD
WY-0064	DRY FORK STATION	10/15/2007	PC BOILER	COAL			LOW NOX BURNERS AND SCR	0.050	lb/MMBtu	12 MONTH ROLLING	BACT-PSD
ND-0024	SPIRITWOOD STATION	9/14/2007	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	LIGNITE	1280	MMBTU/H	FLUIDIZED BED COMBUSTION AND SELECTIVE NON-CATALYTIC REDUCTION	0.090	lb/MMBtu	30 D ROLLING	BACT-PSD

Table 4: EPA RBLC Results for NOx Emissions

RBLCID	Facility Name	Permit Issuance Date	PROCESS Name	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	CONTROL_METHOD_DESCRIPTION	Emission Limit	EMISSION LIMIT UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE_BASIS
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	8/30/2007	CIRCULATING FLUIDIZED BED BOILER	WASTE COAL/BITUMINOUS BLEND	1445	MMBTU/H	SNCR	0.080	lb/MMBtu	30-DAY ROLLING	BACT-PSD
OK-0118	HUGO GENERATING STA	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)		750	MW	LOW NOX BURNERS (LNB) W/ OVERFIRE AIR (OFA) AND SELECTIVE CATALYTIC REDUCTION (SCR)	0.070	lb/MMBtu	30 DAY ROLLING AVERAGE	BACT-PSD
WY-0063	WYGEN 3	2/5/2007	PC BOILER	SUBBITUMINOUS COAL	1300	MMBTU/H	SCR/LNB/OVERFIRE AIR	0.050	lb/MMBtu	12 MONTH ROLLING	BACT-PSD
PA-0259	CAMBRIA COKE CO.	8/25/2006	PYROPOWER UNIT A	COAL			COMBUSTION STAGING	0.300	lb/MMBtu	30 DAY ROLLING AVERAGE	LAER
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	4/26/2006	CIRCULATING FLUIDIZED BED BOILER (CFB)	WASTE COAL	1070	mmbtu/h	SNCR	0.100	lb/MMBtu	30-DAY	BACT-PSD
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	1/27/2006	PULVERIZED COAL BOILER - UNIT 1	COAL	4000	T/H		0.100	lb/MMBtu	30 DAYS ROLLING AVERAGE	N/A
PA-0249	RIVER HILL POWER COMPANY, LLC	7/21/2005	CFB BOILER	WASTE COAL			SNCR INSTALLED. NOX EMISSIONS MONITORED BY CEM	0.100	lb/MMBtu	24-HR AVE.	LAER
PA-0248	GREENE ENERGY RESOURCE RECOVERY PROJECT	7/8/2005	2 CFB BOILERS	WASTE COAL	358	T/H (each)	SNCR, NOX CEM	0.080	lb/MMBtu	30 DAY ROLLING AVERAGE	LAER
NV-0036	TS POWER PLANT	5/5/2005	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	2030	MMBTU/H	SCR & LOW NOX BURNERS	0.067	lb/MMBtu	24-HOUR ROLLING	BACT-PSD

Appendix B.4 - Fernley Plant, Nevada Cement Company

Appendix B.4.a	NDEP Reasonable Progress Control Determination for Fernley Plant
Appendix B.4.b	Nevada Cement Company Four-Factor Analysis for Fernley Plant
Appendix B.4.c	Response Letter 1
Appendix B.4.d	Response Letter 2
Appendix B.4.e	NCC Email

Appendix B.4.a - NDEP Reasonable Progress Control Determination for Fernley Plant

Fernley Plant Reasonable Progress Control Determination

Evaluation of existing and potential new control measures at Nevada Cement Company's Fernley Plant necessary to achieve reasonable progress for Nevada's second Regional Haze SIP.

Bureau of Air Quality Planning, Nevada Division of Environmental Protection

June 2022

1 Introduction

This document serves as the official reasonable progress determination for the Fernley Plant based on analyses submitted by the owner of the facility. The Long-Term Strategy of Nevada's Regional Haze SIP revision for the second implementation period covering years 2018 through 2028 will rely on the reasonable progress findings of this document.

This reasonable progress determination references data and analyses provided by Nevada Cement Company (NCC) in multiple documents that can be found in Appendix B.4. Table 1-1 below outlines the documents submitted by NCC that supplement this determination document. In some cases, the Nevada Division of Environmental Protection (NDEP) adjusted information submitted by NCC to ensure the analyses relied on to make reasonable progress determinations agree with Regional Haze Rule regulatory language, Regional Haze Rule Guidance for the second implementation period, and EPA's Control Cost Manual. Throughout the document, it can be assumed that referenced data and information rely on the following documents submitted by NCC, unless explicitly indicated that NDEP made adjustments.

Table 1-1: NCC Documents Relied upon for Reasonable Progress Determination

Full Document Title	Shortened Document Title (used in this document)	Date	Appendix Location
Regional Haze – Four Factor Analysis	*NCC Analysis*	October 2020	B.4.b
RE: Regional Haze Four Factor Analysis SO_2 Response to NDEP Comments	*Response Letter 1*	November 3, 2020	B.4.c
RE: Regional Haze Four Factor Analysis SO_2 Response to NDEP Comments	*Response Letter 2*	January 7, 2021	B.4.d
Regional Haze Email	*NCC Email*	September 20, 2019	B.4.e

2 Facility Characteristics

Nevada Cement Company's (NCC) Fernley Plant is a Portland cement manufacturing plant located in Fernley, Nevada, consisting of two coal-fired long-dry process kilns. Portland cement produced by NCC is a cementitious, crystalline compound composed primarily of calcium, aluminum, and iron silicates. Both kilns are rated at 30.55 tons per hour of clinker, translating to about 267,500 tons per year clinker for each kiln, or 535,000 tons per year plantwide.

3 Ongoing USEPA Consent Decree

The Fernley Plant is currently bound to the requirements of a USEPA Consent Decree to control NO_x and SO_2 emissions, which can be found via the following links:

United States of America v. Nevada Cement Company, Civil Action No. 3:17-cv-00302-MMD-WGC

https://www.justice.gov/enrd/consent-decree/file/1089586/download

https://www.justice.gov/enrd/consent-decree/file/1089596/download

To control SO_2 emissions, the Consent Decree requires that both kilns at the Fernley Plant emit no more than 1.1 pound of SO_2 per ton of clinker. The facility relies on inherent scrubbing of SO_2 emissions within the cement kilns and has since installed a Dry Sorbent Injection system to assist in achieving the relevant emission limits for both kilns. The Consent Decree ultimately requires that the 1.1 pound of SO2 per ton of clinker emission rate be incorporated into the facility's Title V operating permit.

To control NO_x emissions, the facility is required to install Selective Non-Catalytic Reduction (SNCR), followed by Low-NO_x Burners. Currently, the facility has installed SNCR on both kilns and is in the demonstration period. As stated in Appendix A of the Consent Decree, after the demonstration period, the source is to submit a demonstration report for each kiln's SNCR performance. A final 30-day rolling average emission limit for NO_x for both kilns is then derived from the findings of the demonstration report. Once approved by EPA, or an alternative 30-day rolling average emission limit is provided by EPA, the new NO_x limit associated with the SNCR systems for both kilns is permanently incorporated into the Fernley Plant's NDEP air quality operating permit. The same procedure is required for the implementation of Low-NO_x Burners for each kiln.

The Consent Decree also required the installation and continued use of Continuous Emission Monitoring Systems (CEMS) for both kilns to measure and monitor SO_2 and NO_x emissions. The facility has since implemented CEMS for both kilns successfully and relies on CEMS for SO_2 and NO_x emissions reporting.

NDEP is relying on the referenced Consent Decree to screen the facility out of further consideration of potential new control measures, as the outcome of the Consent Decree will inherently make both kilns BACT for NO_x, SO_2, and PM_{10} emissions. Once NCC has developed and finalized all associated limits to the consent decree controls, it is required that these new limits be incorporated into the facility's Title V permit, making the controls federally enforceable and permanent.

NDEP does not consider the installation and continued use of SNCR and Low-NO_x Burners at both Fernley Plant kilns as necessary to achieve reasonable progress, as NDEP is incapable of determining emissions limits, associated requirements, and compliance schedules for the NO_x controls in a manner that would satisfy the applicable SIP requirements. Furthermore, anticipated reductions from the implementation of NO_x controls and achievement of new SO_2 limits required by the consent decree were not included in the 2028 RPGs developed in Chapter 6 for Jarbidge WA.

NDEP concludes that the consent decree controls for NO_x and SO_2 are not necessary to achieve reasonable progress as these new consent decree controls, and associated limits, will become federally enforceable and permanent through the source's Title V operating permit, as required by the USEPA Consent Decree, regardless of whether they are included in Nevada's Long-Term Strategy for the second implementation period of Regional Haze as necessary to achieve reasonable progress.

A consideration of whether existing PM_{10} controls at both Fernley Plant kilns are necessary to achieve reasonable progress is provided below.

4 Emissions Profile

4.1 Q/d Emissions Profile

NDEP relied on the Q/d method for source selection by quantifying total facility-wide NO_x, SO_2, and PM_{10} emissions, represented as "Q", reported in the 2014 NEIv2. The Q value was then divided by the distance, in kilometers, between the facility and the nearest Class I area (CIA), represented as "d". The nearest CIA to the Fernley Plant is Desolation Wilderness at 102 kilometers away. NDEP elected to set a Q/d threshold of 5. As displayed in Table 3-1, using 2014 NEIv2 emissions, the Pilot Peak Plant yielded a Q/d value of 14.5, effectively screening the facility into a four-factor analysis requirement for the second round of Regional Haze in Nevada.

Table 3-1: Fernley Plant Q/d Derivation

NO_x Emissions (tpy)	SO_2 Emissions (tpy)	PM_{10} Emissions (tpy)	Total Q (NO_x+SO_2+ PM_{10})	Distance from Nearest CIA (Jarbidge WA) [km]	Q/d
1,105	126	252	1,482	102	14.5

As stated above, Q/d calculations for the Fernley Plant relied on facility emissions reported in the 2014 NEIv2. However, using the CEMS required by the ongoing USEPA Consent Decree, Nevada Cement Company has revisited and refined the amount of annual NO_x and SO_2 emissions that were reported for the facility in 2014. New 2018 CEMS data reported NO_x and SO_2 emissions rates that were significantly higher than the emission rates assumed and used in calculating 2014 NEIv2 emissions. NV Cement, referenced in the *NCC Email*, has since proposed more accurate emission rates (see Table 3-2), and subsequent annual emissions, for the year 2014. Table 3-3 calculates a new Q/d value of 30.9 using the updated NO_x and SO_2 emissions. This new Q/d value does not change the original source selection outcome for the Fernley Plant.

Table 3-2: Fernley Plant Updated 2014 Emission Rates from 2018 CEMS

Kiln	#1	#2
NO_x	336.46 lb/hr	326.79 lb/hr
SO_2	42.89 lb/hr	42.89 lb/hr

Table 3-3: Updated Fernley Plant Q/d Derivation

NO_x Emissions (tpy)	SO_2 Emissions (tpy)	PM_{10} Emissions (tpy)	Total Q (NO_x+SO_2+PM_{10})	Distance from Nearest CIA (Jarbidge WA) [km]	Q/d
2,568	332	252	3,152	102	30.9

Note that 2014 NEIv2 emissions were used in projecting the Fernley Plant's baseline 2028 emissions profile to be used in modeling visibility in Jarbidge at the end of the implementation period. Because of this, this increase in emissions must be incorporated into the final 2028 visibility projections, or

Reasonable Progress Goals, for Nevada's second implementation period to provide the most accurate 2028 projection. This is discussed further in Chapter 5 and 6 of Nevada's Regional Haze SIP revision.

4.2 Emissions Baseline for Four-Factor Analysis

NDEP is relying on the baseline SO_2 emissions calculated by NCC for both kilns in *Response Letter 1*. The emissions baseline is summarized in Table 4-4. These baseline emissions represent available SO_2 emissions that could be reduced, after DSI has already been used to meet the SO_2 emission limit requirements listed in the consent decree.

Table 4-4: Baseline SO_2 Emissions for Four-Factor Analysis

Kiln	Baseline SO_2 Emissions (tpy)
1	114.6
2	106.8

5 PM_{10} Determination for Existing Measures

Both kilns at the Fernley Plant currently operate baghouses for the control of particulate matter.

5.1 Weight-of-Evidence Demonstration

NDEP is relying on the following weight-of-evidence demonstration to conclude that the source's existing measures to control PM_{10} emissions are not necessary to achieve reasonable progress during the second implementation period of the Regional Haze Rule in Nevada.

5.1.1 Historical Emission Rates

The following annual total PM as PM_{10} emission rates were reported by Nevada Cement for both kilns at the Fernley Plant from 2016 through 2020, representing data from the most recent five operating years (see Table 5-1). The most recent five years show a consistent PM emission rate for both kilns at the facility. NDEP considers the trend in total PM emission rates outlined in Table 5-1 as reasoning to assume that the source's achievable emission rates will remain consistent and not increase in the future.

Table 5-1: Historical PM_{10} Achievable Emission Rate Profile for Fernley Plant Kilns

	Reported Annual Total PM Emission Rates (lb/hr)					
	2016	2017	2018	2020	2021	2016-2020 Average
Kiln 1	N/A[1]	5.67	0.514	4.30	11.22[2]	5.43
Kiln 2	3.07	5.08	3.82	1.58	1.55	3.02

5.1.2 Projected Emission Rates

There are no federally enforceable on-the-way controls or changes to operations at the Fernley Plant pertaining to total PM or PM_{10} emissions. Because of this, NDEP finds it reasonable to rely on emissions and emission rates calculated from the 2016-2020 representative historical period to project future

[1] Kiln not in operation at time of Stack Test due to installation of new baghouse

[2] From Stack Test Report: "System 09 also had an extremely high concentration of particulate collected during the first run and very low for the following two runs. Since no major operational changes occurred between the runs, the particulate matter concentration for the first run suggests that the analysis was not conducted correctly. No exceedances in the permitted emission or production limits were reported"

emissions and emission rates. As stated in Table 5-1, the representative historical period, and projection assumption, for Kilns 1 and 2's PM_{10} emission rates are 5.43 and 3.02 pounds per hour, respectively. NDEP concludes that the projected emission rate will remain consistent with historical emission rates.

5.1.3 Enforceable Emission Limits

NDEP is citing the following enforceable emissions limits listed in the facility's current air quality operating permit to control PM_{10} emissions that reflect the source's existing measures as evidence that the source will continue to implement each kiln's baghouse.

From Section VI.H.2.a.(i) of NDEP Permit No. AP3241-0387.02:
"NAC 445B.305 *Part 70 Program* – The discharge of PM_{10} (particulate matter less than 10 microns in diameter) to the atmosphere will not exceed **14.83** pounds per hour, nor more than **64.96** tons per 12-month rolling period."

From Section VI.O.2.a.(i) of NDEP Permit No. AP3241-0387.02:
"NAC 445B.305 *Part 70 Program* – The discharge of PM_{10} (particulate matter less than 10 microns in diameter) to the atmosphere will not exceed **14.83** pounds per hour, nor more than **64.96** tons per 12-month rolling period."

6 SO_2 Determination for Existing Measures

As stated above, the Consent Decree requires that both kilns at the Fernley Plant emit no more than 1.1 pounds of SO_2 per ton of clinker by the relevant compliance date. The facility plans to meet these limits through inherent scrubbing of SO_2 emissions within the cement kilns, as well as the occasional use of Dry Sorbent Injection.

Although the source was not required to consider potential new control measures at the facility for the second round of Regional Haze, NDEP requested that NCC evaluate the cost effectiveness of operating the existing Dry Sorbent Injection at any time that the kiln is in operation (assumed 8760 hours a year). Table 6-1 summarizes the four statutory factors considered for the continuous use of Dry Sorbent Injection (DSI) to control SO_2 emissions at both kilns.

Table 6-1: Summary of 4-Factor Analysis of DSI on both Fernley Plant Kilns

Control	Unit	Cost of Compliance	Time Necessary for Compliance	Energy and Non-Air Quality Impacts	Remaining Useful Life
Dry Sorbent Injection (DSI)	Kiln 1	$30,066/ton	A minimum of 4 months after SIP approval.	Increased energy demand.	20 years
	Kiln 2	$30,140/ton			

6.1 Cost of Compliance

Cost-effectiveness values estimated for the continuous use of the existing DSI system for both kilns provided in *Response Letter 2* have since been updated by NDEP. In this response, incorrect capacity factors were used for both kilns in estimating the additional costs of using the DSI systems year-round. Table 6-2 outlines what NCC submitted in their latest response.

Table 6-2: NCC DSI Costs

DIRECT COSTS:	Kiln 1	Kiln 2
Percent Control	30%	30%
Capacity Factor	0.908	0.896
(1) Operating Labor	$36,693	$36,218
(2) Supervisory Labor	$4,997	$4,868
(3) Maintenance Labor	$45,561	$44,971
(4) Parts and Materials	$64,038	$63,209
(4a) 20-Yr Piping Replacement Costs	$11,220	$11,220
(5) Utilities		
(5a) Electricity	$14,830	$13,818
(6) Lime Reagent	$823,951	$767,750
Total Direct Costs	$1,001,289	$942,053
INDIRECT COSTS:		
(8) Overhead	$37,211	$36,337
(9) Property Tax – Not Allowed Per NRS 361.077	$0	$0
(10) Insurance	$2,154	$2,126
(11) G&A Charges	$4,307	$4,251
(12) Capital Recovery	$14,812	$14,620
(a) Capital Recovery Factor	0.06878	0.06878
Total Indirect Costs	$58,484	$57,334
TOTAL ANNUALIZED COSTS	$1,059,773	$999,388
Tons/year of SO_2 Removed from Both Kilns (30%)	34.4	32.0
COST EFFECTIVENESS ($/ton SO_2 removed)	$30,830	$31,200

NCC stated:

As shown in Table 1 and Table 2 of Attachment A, we have updated our annualized costs to list the capacity factor for each kiln based on the above actual annual hours of operation. The capacity factor is listed in the table and each row of cost data has subsequently been multiplied by the capacity factor. The capacity factor for Kiln #1 is 0.9079 and for Kiln #2 is 0.8962. It should be noted that the capacity factor has not been applied to the electricity or lime reagent costs, as these calculations are based on the actual *additional hours (incremental) the electricity and lime will be used. For Kiln #1 and Kiln #2 this equates to:*

Kiln	*Lime Operating Hours*	*Lime Non-Operating Hours*
1	*(7,953 hr/yr)(0.1426) = 1,134 hr/yr*	*(7,953 hr/yr) - (1,134 hr/yr) = 6,819 hr/yr*
2	*(7,850. Hr/yr)(0.1906) = 1,496 hr/yr*	*(7,850 hr/yr) - (1,496 hr/yr) = 6,354 hr/yr*

NDEP originally requested that “the additional annual hours used to evaluate costs should consist of capacity factor minus the baseline scenario hours.” As can be seen above, the capacity factors calculated based on the total operating hours (including hours that were already utilizing DSI). To correctly evaluate the incremental cost of operating the DSI continuously, the capacity factor should’ve been calculated using the “Lime Non-Operating Hours.” When the correct hours are used, we get a capacity factor of 0.7784 for Unit 1 and 0.7253 for Unit 2. Updated cost-effectiveness figures using these correct capacity factors are included in Table 6-3 below. These new capacity factors were not applied to the electricity and reagent costs since those cost figures were calculated using hours incremental to the existing operating scenario.

Table 6-3: NDEP DSI Costs

DIRECT COSTS:	Kiln 1	Kiln 2
Percent Control	30%	30%
Capacity Factor	**0.7784**	**0.7253**
(1) Operating Labor	$31,460	$29,314
(2) Supervisory Labor	$4,719	$4,397
(3) Maintenance Labor	$39,063	$36,398
(4) Parts and Materials	$54,905	$51,160
(4a) 20-Yr Piping Replacement Costs	$11,220	$11,220
(5) Utilities		
(5a) Electricity	$14,830	$13,818
(6) Lime Reagent	$823,951	$767,750
Total Direct Costs	$980,148	$914,057
INDIRECT COSTS:		
(8) Overhead	$34,570	$32,212
(9) Property Tax – Not Allowed Per NRS 361.077	$0	$0
(10) Insurance	$2,286	$2,130
(11) G&A Charges	$4,572	$4,260
(12) Capital Recovery	$12,698	$11,832
(a) Capital Recovery Factor	0.06878	0.06878
Total Indirect Costs	$54,126	$50,434
TOTAL ANNUALIZED COSTS	$1,034,274	$964,491

Tons/year of SO_2 Removed from Both Kilns (30%)	34.4	32.0
COST EFFECTIVENESS ($/ton SO_2 removed)	**$30,066**	**$30,140**

For the purpose of reasonable progress determinations, NDEP is relying on the newly calculated cost effectiveness figures of $30,066 per ton reduced for Kiln 1, and $30,140 per ton reduced for kiln 2 in considering the implementation of continuous use of the existing DSI system.

6.2 Time Necessary for Compliance

In determining time necessary for compliance, NDEP is relying on NCC's statement provided in Section 5.5 of the *NCC Analysis* that states:

"NCC has indicated that a minimum of 4 months is required to procure, build, install, and "shakedown" the new equipment for proper engineering for the upgrade to a single DSI system."

6.3 Energy and Non-Air Quality Environmental Impacts

In determining energy and non-air quality environmental impacts, NDEP is relying on NCC's statement provided in Section 5.6 of the *NCC Analysis* that states:

"The use of DSI full time (8,760 hr/yr) will have an energy penalty in terms of electricity needed to operate the larger blower (50 hp). The electricity requirement for the DSI system is approximately 39kW per hour (343,889 kW/yr) which equates to $19,051 per year... Kiln 1 and Kiln 2 are currently equipped with an as needed DSI system for SO_2 control. The lime reagent used in a DSI system reacts with SO_2 in the flue gas to form calcium sulfate and calcium sulfite solids. The solids are captured in the existing fabric filter particulate control systems and either returned to the systems for reuse or removed from the systems as nonhazardous solid waste. Collateral environmental impacts associated with the DSI system include increased solid waste generation. Additionally, the operation of the DSI storage vessel's baghouse will emit an additional 0.2 tpy of PM (lime emissions)."

The additional electricity cost outlined above is included in the source's analysis for the cost of compliance. Although the control would require additional electricity to operate at full capacity, NDEP does not find this to be sufficient to warrant a no control determination. The calcium sulfate and calcium sulfite solids are either recycled back into the system or properly disposed of. This does not pose a threat to the surrounding non-air environment. Although there is a 0.2 tpy increase in PM emissions as a result of this control, adding this increase to the total reductions achieved by the control would not be impactful in this analysis.

6.4 Remaining Useful Life of the Source

NDEP is relying on the statement provided by NCC in Section 5.7 of the *NCC Analysis* that states:

"The remaining useful lifetime of both Kiln 1 and Kiln 2 is expected to be longer than the projected lifetime of the pollution control technology (DS) which has been analyzed for these sources. As such, the remaining useful life of the kilns does not impact the annualized costs of DSI because the remaining useful life of both kilns is anticipated to be at a minimum as long as the capital cost recovery period, which is 20 years."

NCC has indicated that cement kilns, similar to lime kilns, typically have a 50-year lifetime that can be extended through maintenance. NDEP agrees that the remaining useful life of the Fernley Plant kilns surpasses the estimated life of the DSI system of 20 years. The cost analysis assumes a 20-year life for the DSI system on both kilns.

6.5 Reasonable Progress Determination

NDEP does not consider the continuous use of the existing DSI system on both kilns as cost-effective, or necessary to achieve reasonable progress.

7 NO_x Determination for Existing Measures

There are no existing NO_x control measures at the Fernley Plant kilns that could be considered necessary to achieve reasonable progress during the second round.

8 Control Measures Necessary to Make Reasonable Progress

NDEP concludes that both existing and new control measures at the Fernley Plant kilns are not necessary to make reasonable progress during the second implementation period of Nevada's Regional Haze SIP.

Appendix B.4.b - Nevada Cement Company Four-Factor Analysis for Fernley Plant

FERNLEY, NEVADA
PORTLAND CEMENT PLANT

Regional Haze – Four Factor Analysis

Prepared for:

Nevada Cement Company

October 2020

SLR

Regional Haze - Four Factor Analysis

Prepared for:
Nevada Cement Company

Fernley, Nevada

This document has been prepared by SLR International Corporation (SLR). The material and data in this report were prepared under the supervision and direction of the undersigned.

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1. INTRODUCTION AND BACKGROUND

On August 12, 2019 the Nevada Division of Environmental Protection, Bureau of Air Quality Planning (NDEP) sent a letter requesting that Nevada Cement Company (NCC) perform a four-factor analysis (4FA) of its Portland Cement Plant (Plant) located in Fernley, Nevada. This request was based on a screening analysis (Q/d), which is an early step in NDEP's required process to update their Regional Haze Rule (RHR) state implementation plan (RHSIP). The results of NDEP's screening analysis indicated that NCC's Plant operations may be impacting a Prevention of Significant Deterioration (PSD) Class I area (Desolation Wilderness) in Nevada.

The State of Nevada is required by EPA to submit an updated RHSIP by July 2021. This RHSIP must implement a long-term strategy (LTS) to ensure the RHR requirements are on track. In August 2019, EPA issued the following guidance: *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (Guidance). It should be noted that this second planning period for the RHR will be a new process and is a departure from the first planning period that was based on the BART regulations. EPA made changes to the RHR in 2016 and finished the final guidance in August 2019 to meet the regulatory schedule of the second planning period.

The Guidance provides an overview of the expected steps that states and regional planning organizations (RPOs) will take to meet the July 2021 deadline. These include:

1. Ambient data analysis (of measured visibility data);
2. Determination of affected Class I areas in other states
3. Selection of sources for analysis;
4. Four-factor analyses for selected sources;
5. Decisions on what control measures are necessary to make reasonable progress
6. Regional-scale modeling;
7. Demonstrate progress and glidepath check; and
8. Additional requirements for RHSIPs.

The first step is used to determine current visibility in the Class I areas, its relationship to the expected visibility reduction glidepath, the determination of 20% most impaired days, and the 20% clearest days over the previous five years. The determination in the 20% impaired/clearest must now include a determination of daily anthropogenic impairment. As part of this analysis, information about the anthropogenic extinction budgets at Class I areas will be determined, which can help to provide information about source attribution, changes to emission levels, and transport patterns.

The second step requires each state to include Class I areas in neighboring states in their analyses.

The third step in this process is source screening, by which WDEQ will identify sources that must perform a 4FA. The guidance provides states with significant latitude on how this screening is performed and interpreted. Specific screening thresholds are not recommended by EPA nor have been provided by NDEP. Rather, EPA recommends that states should include (screen in) sufficient facilities so that at least 80% of the state emissions are required to do a 4FA. However, EPA also notes that this 80% inclusion approach may not be appropriate if Q/d is used as the screening analysis. Since NDEP did use Q/d, their inclusion based on this approach could be explored for possible exclusion from the program.

The fourth step in this process is the 4FA, which considers the following four factors:

1. The cost of compliance;
2. Time necessary for compliance;
3. Energy and non-air environmental impacts; and
4. Remaining useful life of the source.

After reviewing NDEP's August 12, 2019 letter and subsequent conversations, NDEP requested NCC provide additional information regarding the Plant's current operations and status of the Consent Decree (CD) with the EPA regarding the level of controls that are either in place or are currently being installed pertaining to the control of emissions for Nitrogen Oxides (NO_x), Sulfur Dioxide (SO_2), and Particulate Matter (PM) at the Plant.

On January 9, 2020 NCC provided the requested information for NDEP's review and consideration (NCC 2020). On September 24, 2020 NCC and NDEP had a conference call regarding NCC's January 9, 2020 letter response. During this conversation, NDEP concurred with NCC's findings that a 4FA is not necessary for NO_x and PM emission controls. However, NDEP requested that NCC perform a 4FA for SO_2 emissions from Kiln 1 and Kiln 2 at the Plant. As noted above, in 2017, NCC entered into a CD agreement with the EPA regarding the control of NO_x and SO_2 emissions from Kiln 1 and Kiln 2. As part of that CD, NCC was required to meet an emission limit for each kiln of 1.1 lb SO_2/ton clinker (30-day rolling average) or 294.4 tpy total SO_2. NCC had chosen a catalytic filter bag technology for the control of NO_x emissions; however, this technology required a SO_2 concentration limitation prior to the catalytic filter bags in order to prevent catalyst contamination. As a result, NCC installed the capability to inject dry sorbent (lime) for additional SO_2 control other than utilizing process controls. Following several months of performance failures of the catalytic bag technology, NCC removed this control technology and installed the SNCR technology which does not have a SO_2 concentration limitation. Therefore, the only reason the Dry Sorbent Injection (DSI) system was installed was for additional "as needed" SO_2 control for a NO_x control technology that was ultimately deemed technically infeasible and replaced with SNCR technology.

NCC's current operations allow for the continued operation of the DSI system on an as needed basis. NDEP has requested that NCC perform a 4FA for operating the DSI system 8,760 hours per year (hr/yr) instead of on an as needed basis. No additional SO_2 controls are required to be evaluated as part of this 4FA. NCC disagrees with the NDEPs statement that the cost for controls that are currently installed should not be included in the analysis. As stated above, NCC only installed lime injection for the NOx control project. Had NCC not chosen the catalytic bag filter NOx control technology, NCC would not have installed the lime injection system since the facility has been able to manage compliance with the state permit limit on a short-term basis and would have used operational controls to ensure the CD limit was met on a 30-day rolling average. As a result, the \$2.2 million of capital cost NCC incurred was not included in this analysis thus skewing the analysis putting NCC at an economic disadvantage to other cement plants conducting a similar analysis.

This document provides the results of the 4FA for SO_2 emissions from the two kilns at the Plant in Fernley, Nevada. Section 2 contains information describing the facility, site location, and existing equipment. Details of the baseline emissions used to conduct the analysis presented herein can be found in Section 3. Section 4 provides a discussion of 4FA methodology. The 4FA can be found in Section 5 and evaluates DSI for technical feasibility and cost effectiveness when operating at 8,760 hr/yr. Section 5 also provides typical timelines required to design, engineer, procure and install the DSI system and identifies the energy and non-air quality environmental impacts associated with DSI. A discussion of the planned remaining useful life of the sources reviewed is also discussed in Section 5. Section 6 provides a summary and conclusion.

2. FACILITY DESCRIPTION

NCC owns and operates a Portland cement manufacturing plant in Fernley, Nevada. The existing facility consists of two long-dry process kilns, Kiln No. 1 (Kiln 1) and Kiln No. 2 (Kiln 2). The Portland cement produced by NCC is a cementitious, crystalline compound composed primarily of calcium, aluminum and iron silicates. Limestone containing calcium carbonate and aluminum, iron, and silicon oxides, clay and sand are combined and fired in the long-dry kilns where the raw materials are calcinated and sintered through the pyro-process to create cement clinker. The cement clinker is then refined by grinding and milling and stored for shipping.

Kiln 1 and Kiln 2 are both rated at 30.55 ton per hour of clinker (~267,500 ton per year [tpy] clinker each). Total clinker capacity for the Plant is approximately 535,000 tpy clinker.

Particulate emissions from the kilns themselves are controlled by two baghouses, one for each kiln. In 2017, NCC installed a new main baghouse on the Kiln 1 system and installed polishing fabric filters upstream of each main baghouse on Kiln 1 and Kiln 2. These installations were conducted to comply with applicable PM emission limits, but also allowed for carbon injection to meet the applicable mercury emission limits.

Emissions of SO_2 generated from the combustion of the coal/coke blend used by NCC, are controlled by the rotary kiln process itself. The advantage of using a rotary kiln process is that the SO_2 gases are exposed to the lime and limestone dust in the kiln and baghouse and are reduced through this natural dry scrubbing process (inherent dry scrubbing). The Plant has also installed the capability to inject dry sorbent (lime) on an as needed basis for additional SO_2 control other than utilizing process controls.

The following table provides the design parameters used for the NCC Kiln 1 and Kiln 2 four factor analysis. The parameters are for each Kiln***.***

	KILN 1	KILN 2
Design	Direct-Fired Long-Dry Rotary Kiln	Direct-Fired Long-Dry Rotary Kiln
Design Rate	30.55 ton/hr CL	30.55 ton/hr CL
Baseline SO_2 Emissions [1]	147.2 tpy	147.2 tpy
Fuel	Coal / Pet Coke / Natural Gas	Coal / Pet Coke / Natural Gas
PM Control	Baghouse + Polishing Fabric Filter	Baghouse + Polishing Fabric Filter
SO_2 Control	Dry Sorbent Injection	Dry Sorbent Injection
NO_x Control	Selective Non-Catalytic Reduction (SNCR)	Selective Non-Catalytic Reduction (SNCR)

[1] 2017 Consent Decree (CD) with EPA. Each kiln limited to 1.1 lb SO_2/ton CL (30-day rolling average) or 294.4 tpy total.

3. BASELINE EMISSIONS

3.1 GENERAL

This section summarizes the baseline emission rates used for the 4FA. NDEP's letter dated August 12, 2019 indicated that the screening analysis (Q/d) was based on actual emissions for the year 2014 from EPA's 2014 National Emissions Inventory as summarized in **Table 3-1**. However, it should be noted that the NO_x and SO_2 emissions from 2014 were revised based on an email submittal to the NDEP on September 20, 2019 to more accurately reflect the emissions during this period. **Table 3-2** provides the revised emissions.

Table 3-1 - NCC Plant Q/d Analysis

Facility	Nearest Class I Area	D	NO_x	SO_2	PM_{10}	Sum	Q/d
Fernley Plant	Desolation Wilderness	102 km	1,104.6 tpy	125.9 tpy	251.5 tpy	1,482 tpy	14.5

Table 3-2 - NCC Plant Q/d Analysis - Revised

Facility	Nearest Class I Area	D	NO_x	SO_2	PM_{10}	Sum	Q/d
Fernley Plant	Desolation Wilderness	102 km	2,567.9 tpy	332.1 tpy	251.5 tpy	3,151.5 tpy	30.9

Based on the information NCC presented in the January 9, 2020 letter, NDEP indicated that PM_{10} and NO_x emissions do not warrant review for control analyses and do not need to be evaluated as part of the 4FA. In summary, only SO_2 emissions from Kiln 1 and Kiln 2 were required to be evaluated in this 4FA.

The majority of SO_2 emissions are emitted from Kiln 1 and Kiln 2 at the Plant. **Table 3-3** provides the permitted allowable SO_2 emissions for Kiln 1 and Kiln 2. Class I Air Quality Operating Permit AP3241-0387.03 (Permit No. AP3241-0387.03) was issued January 27, 2009 for a term of five years and expired on January 27, 2014. A timely application for renewal was submitted June 3, 2013 and continued operation of the Plant under the expired permit was allowed pursuant to NAC 445.3443(4). However, NDEP did not issue a new Class I Air Quality Operating Permit during the five-year permit term and NCC was required to submit a complete Class I renewal application not later than April 2, 2018. NCC submitted a timely renewal application that was deemed complete on June 1, 2018. To date NCC has not received a new final permit and continues to operate under the expired Permit No. AP3241-0387.03.

Table 3-3 - NCC Permitted Allowable SO_2 Emissions (Kiln 1 & Kiln 2)

Source	SO_2 Emission Rates	
Kiln 1	42.89 lb/hr	187.9 tpy
Kiln 2	42.89 lb/hr	187.9 tpy
	Total	**375.80 tpy**

As stated above, it was determined that the 2014 data used for the screening analysis contained in **Table 3-1** was not correct and the table was revised as shown in **Table 3-2**. On October 15, 2019 Sig Jaunarajs of the NDEP indicated that:

> *"For purposes of determining the beneficial emission reductions that will result from the installation of the new control equipment you are currently engaged in, we would favor using the most recent annual emissions rates that you feel are representative of plant operating conditions pre-consent decree."*

Table 3-4 represents the annual SO_2 emission rates that NCC provided to the NDEP that we felt were representative of plant operating conditions pre consent decree.

Table 3-4 - NCC SO_2 Baseline Emissions (Kiln 1 & Kiln 2) Pre-Consent Decree

Source	SO_2 Emission Rates		
Kiln 1	1.404 lb/ton CL	42.89 lb/hr	166.60 tpy
Kiln 2	1.404 lb/ton CL	42.89 lb/hr	165.50 tpy
		Total	**332.10 tpy**

However, as discussed previously, on September 24, 2020 NCC and NDEP participated in a conference call regarding NCC's January 9, 2020 letter response, whereby NDEP requested NCC perform a 4FA for SO_2 emissions from Kiln 1 and Kiln 2 with the DSI system operating 8,760 hr/yr instead of on an as needed basis. Since NDEP is requesting the analysis be performed for DSI operating 8,760 hr/yr, and the kilns are limited by the consent decree to 1.1 lb/ton CL or 294.4 tpy on that basis, NCC determined that normal operations would be best represented using post-consent decree allowable emissions as shown in **Table 3-5**.

Table 3-5 - NCC SO_2 Baseline Emissions (Kiln 1 & Kiln 2) Post-Consent Decree

Source	SO_2 Emission Rates		
Kiln 1	1.1 lb/ton CL	33.61 lb/hr	147.2 tpy
Kiln 2	1.1 lb/ton CL	33.61 lb/hr	147.2 tpy
		Total	**294.4 tpy**

4. FOUR FACTOR ANALYSIS METHODOLOGY

4.1 GENERAL

As discussed previously, the results of WDEQ's screening analysis (Q/d) indicated that NCC's Fernley Plant may be impacting a PSD Class I area (Desolation Wilderness). As a result, NDEP requested that a 4FA be performed to determine if there are any "reasonable" controls available for reducing visibility impairing emissions of SO_2 for Kiln 1 and Kiln 2. The 4FA considers the following four factors:

1. The cost of compliance;
2. Time necessary for compliance;
3. Energy and non-air environmental impacts; and
4. Remaining useful life of the source.

The following steps must be followed in conducting the four-factor analysis:

- Identify all available control technologies;
- Eliminate technically infeasible options;
- Rank the remaining options based on effectiveness;
- Analyze the most effective measure and document the results; and
- Establish federally enforceable emission limits and/or other requirements.

4.2 FACTOR 1 – COST OF COMPLIANCE

4.2.1 COST EFFECTIVENESS METHODOLOGY

The basis for comparison in the economic analysis of the control scenarios is the cost effectiveness; that is, the value obtained by dividing the total net annualized cost by the tons of pollutant removed per year for each control technique. Annualized costs include the annualized capital cost plus the financial requirements to operate the control system on an annual basis, including operating and maintenance labor, and such maintenance costs as replacement parts, overhead, raw materials, and utilities. Capital costs include both the direct cost of the control equipment and all necessary auxiliaries as well as both the direct and indirect costs to install the equipment. Direct installation costs include costs for foundations, erection, electrical, piping, insulation, painting, site preparation, and buildings. Indirect installation costs include costs for engineering and supervision, construction expenses, start-up costs and contingencies.

To accurately estimate the total annualized cost of a particular control technology, a conceptual design must be developed in sufficient detail to quantify all the direct capital and operating costs. All costs are then expressed as an annualized cost as well as calculated cost-effectiveness values. This approach of amortizing the investment into equal end-of-year annual costs is termed the Equivalent Uniform Annual Cost (EUAC) (Grant, Ireson and Leavenworth 1990). It is very useful when comparing the costs of two or more alternative control systems and is the USEPA-recommended method of estimating control costs. The EUAC costs and estimating methodology used in this report are directed toward a "study" estimate of ±30 percent accuracy that is described in the USEPA's OAQPS Control Cost Manual (USEPA 2017). According to the Chemical Engineer's Handbook (Perry and Chilton 2008), a study estimate is "...used to estimate the economic feasibility of a project before expending significant funds for piloting, marketing, land surveys, and acquisition... [however] it can be prepared at relatively low cost with minimum data." Capital and annual cost estimating methodology is described below.

4.2.2 CAPITAL COSTS

Several methods with varying degrees of accuracy are available for estimating capital costs of pollutant control devices. Cost estimating techniques range from the simple "survey method" whereby the total installed costs are equated to a basic operating parameter (e.g., gas flow rate) to detailed cost estimates based on preliminary designs, systems drawings, and contractor quotes. Survey method cost algorithms are derived from industry surveys of overall capital costs of installed equipment and represent the average cost of many installations. Since there are no provisions that permit normalization of the many site-specific parameters which affect both equipment and installation costs, survey methods provide accuracies, at best, on the order of +50 percent to -30 percent (Vatavuk and Neveril 1980, and USEPA 2017).

Detailed cost estimates on the other hand, including obtaining detailed vendor quotations against detailed engineering bid packages, will provide better accuracies that are commensurate to the level of design detail obtained and included in the bid package (i.e. 15/30/60/90/100% level). Each higher level of design will require substantially more engineering work to develop with the cost rising accordingly. Detailed designs are not generally obtained for BACT analyses due to the substantial costs occurred and the speculative nature of the project. Generally, the approach taken in a BACT analysis is to obtain vendor-supplied control equipment cost estimates for similar facilities and apply a factored approach for estimating ancillary equipment and installation costs to obtain reasonably accurate installed capital costs for controls.

4.2.3 ANNUALIZED COSTS

Annualized costs are comprised of the direct operating costs of materials and labor for maintenance, operation, supervision and utilities and waste disposal, and the indirect operating charges, including plant overhead, general and administrative, and capital charges. These generalized factors may in some cases be modified to provide more accurate, site-specific values. Utility costs for the control device and auxiliary equipment are based on the total annual consumption, unit costs, and vendor estimates. The cost of electrical power is based on $0.0554/kW-hr.

Indirect operating costs include the cost of plant overhead, general and administrative (G&A), and capital charges. G&A is a direct function of the total capital cost. Overhead is a function of both labor (payroll and plant) and project capital cost. The capital recovery cost, or capital charge, is based on the operational life of the system, interest and capital depreciation rates, and total capital cost. These charges are based on the capital recovery factor (CRF) defined as:

$$CRF = i\,(1+i)^n / [(1+i)^n - 1]$$

where: i = the annual interest rate; and
n = equipment life (years).

For this economic analysis, the capital recovery factor was calculated as 0.06878, which assumes that the equipment life is 20 years and the average annual interest rate is 3.25 percent (EMI 2020). The interest rate was determined from the bank prime rate published by the Board of Governors of the Federal Reserve System[1]. The bank prime rate is the "rate posted by a majority of the top 25 (by assets in domestic offices) insured U.S. chartered commercial banks (USEPA 2017). Based on the above cost estimating procedures, capital and annualized costs have been estimated for each potential emission control alternative studied. These costs are budgetary estimates, provided for comparative purposes only, and are not final costs. The estimated capital and operating costs do not include all components that are encountered in a project of this nature; therefore, the costs presented are conservative. Specific capital and annualized cost calculations (if applicable) are discussed in the cost of compliance evaluation.

The basis for comparing the economic impacts of control scenarios is cost effectiveness. This value is defined as the total net annualized cost of control, divided by the actual tons of pollutant removed per year, for each control technique. Annualized costs include the capital cost plus the financial requirements to operate the control system on an annual basis, including operating and maintenance labor, replacement parts, overhead, raw materials, waste disposal and utilities. Capital costs include both the direct and indirect costs to install the equipment. Direct installation costs include costs for foundations, erection, electrical, piping, insulation, painting, site preparation, and buildings. Indirect installation costs include costs for engineering and supervision, construction expenses, startup costs and contingencies.

4.3 FACTOR 2 – TIME NECESSARY FOR COMPLIANCE

Factor 2 involves the evaluation of the amount of time needed for full implementation of the different control strategies. The time for compliance will need to be defined and should include the time needed to develop and implement the regulations, as well as the time needed to install the necessary control equipment. The time required to install a retrofit control device includes time for capital procurement, device design, fabrication, and installation. The Factor 2 analysis should also include the time required for staging the installation of multiple control devices at a given facility if applicable.

[1] Board of Governors of the Federal Reserve System. "Selected Interest Rate (Daily) – H.15." Available at: https://www.federalreserve.gov/releases/h15/ (Accessed October 14, 2020)

4.4 FACTOR 3 – ENERGY AND OTHER IMPACTS

Energy and environmental impacts analyzed as part of this step generally include the following but are not limited to and/or need to be included in the analysis:

Energy Impacts

- Electricity requirement for control equipment and associated fans
- Steam required
- Fuel required

Environmental Impacts

- Waste generated
- Wastewater generated
- Additional carbon dioxide (CO_2) produced
- Reduced acid deposition
- Reduced nitrogen deposition
- Negative impacts on visibility and regional haze

Non-air environmental impacts (positive or negative) can include changes in reagent chemicals and water usage and waste disposal of spent catalyst or reagents. EPA recommends that the costs associated with non-air impacts be included in the Cost of Compliance (Factor 1). Other effects, such as deposition or climate change due to greenhouse gases (GHGs) do not have to be considered.

For this analysis we evaluated the direct energy consumption of the emission control device, solid waste generated, wastewater discharged, acid deposition, nitrogen deposition, any offsetting negative impacts on visibility from controls operation, and climate impacts (e.g., generation and mitigation of greenhouse gas emissions).

In general, the data needed to estimate these energy and other non-air pollution impacts were obtained from the cost studies which were evaluated under Factor 1. These analyses generally quantify electricity requirements, steam requirements, increased fuel requirements, and other impacts as part of the analysis of annual operation and maintenance costs.

Costs of disposal of solid waste or otherwise complying with regulations associated with waste streams were included under the cost estimates developed under Factor 1, and were evaluated as to whether they could be cost-prohibitive or otherwise negatively affect the facility.

Indirect energy impacts were not considered, such as the different energy requirements to produce a given amount of coal versus the energy required to produce an equivalent amount of natural gas.

4.5 FACTOR 4 – REMAINING EQUIPMENT LIFE

Factor 4 accounts for the impact of the remaining equipment life on the cost of control. Such an impact will occur when the remaining expected life of a particular emission source is less than the lifetime of the pollution control device that is being considered.

In this case, the capital cost of the pollution control device can only be amortized for the remaining lifetime of the emission source. Thus, if a control device with a service life of 15 years is being evaluated for a boiler with an expected remaining life of 10 years, the shortened amortization schedule will increase the annual cost of the control device.

In general, a cement kiln has a design life of 50 years, and they are typically designed to allow component and subcomponents that allow independent change-outs. This can significantly extend the life of the kiln. Industrial processes often refurbish cement kilns to extend their lifetime. As such the remaining lifetime of the equipment is expected to be longer than the projected lifetime of the pollution control technologies that were analyzed for this 4FA.

5. FOUR FACTOR ANALYSIS – SO_2

5.1 INTRODUCTION

This section describes the 4FA for the control of SO_2 emissions from the two existing kilns (Kiln 1 and Kiln 2) currently operating at the NCC Fernley Portland Cement Plant. As discussed, and outlined in Section 4.1, the 4FA considers the following four factors:

1. The cost of compliance;
2. Time necessary for compliance;
3. Energy and non-air environmental impacts; and
4. Remaining useful life of the source.

The following steps must be followed in conducting the four-factor analysis:

- Identify all available control technologies;
- Eliminate technically infeasible options;
- Rank the remaining options based on effectiveness;
- Analyze the most effective measure and document the results; and
- Establish federally enforceable emission limits and/or other requirements.

5.2 SO_2 RACT/BACT/LAER CLEARINGHOUSE REVIEW

An important consideration in reviewing potential control technologies and emission limits is past determinations for similar sources. A review of the RACT/BACT/LAER database (RBLC) on the U.S. EPA TTN web site was performed to identify previous control technology determinations for Portland cement kilns (USEPA 2020). This database contains information reported by state and local agencies on RACT (Reasonably Available Control Technology), BACT (Best Available Control Technology), and LAER (Lowest Achievable Emission Rate) determinations made on a case-by-case basis during permit application reviews. It should be noted that given NDEP's direction to only review DSI operating on a full time basis, the database review was used to determine emission limits and/or control efficiency of DSI and not used to evaluate other control technologies. Results of this search are summarized in **Table 5-1**. Emission rates range from 0.4 pound SO_2 per ton of clinker (lb SO_2/ton CL) to 1.1 lb SO_2/ton CL. LAER is defined as circulating fluidized bed absorber or equivalent, while BACT is defined as lime injection as needed, fabric filter, and good combustion practices (GCP). It should be noted that each of the kilns listed in **Table 5-1** are 5-stage preheater/precalciner type design with in-line raw mills (additional inherent natural SO_2 scrubbing) as opposed to being long-dry kiln design like those operated by NCC.

Table 5-1 - U.S. EPA SO_2 RACT/BACT/LAER Clearinghouse – Portland Cement Kilns

RBLC ID	Company / Facility	(Permit Issued) Last Update	Kiln Type	SO_2 Emission Limit	Control Technology	Basis
GA-0136	CEMEX Southeast LLC	(01/27/2010) 05/18/2010	Preheater/Precalciner w/in-line raw mill -New Kiln #6	1.0 lb/ton CL; 30-day rolling average	Judicious Selection/Use of Raw Materials, Hydrated Lime Injection as Necessary	BACT-PSD
IL-0111	Universal Cement	(12/20/2011) 09/06/2013	Preheater/Precalciner w/in-line raw mill– New	0.4 lb/ton CL; 30-day rolling average	Adsorption in CL/kiln dust, & add-on circulating fluidized bed absorber or equivalent	LAER
KS-0031	Ash Grove Cement Co.	(07/14/2017) 07/19/2017	Preheater/Precalciner – Modification	1.10 lb/ton CL; 1,037 tpy	Fabric Filters	PSD Avoidance
TX-0822	Capital Aggregates Inc.	(06/30/2017) 11/16/2017	Preheater/Precalciner w/in-line raw mill- New	0.4 lb/ton CL; 30-day rolling average	Good Combustion Practices	BACT-PSD
TX-0866	Texas Lehigh Cement Co.	(10/24/2019) 11/06/2019	Preheater/Precalciner w/in-line raw mill – New Kiln #2	1.0 lb/ton CL	Lime Injection into Exhaust Stream before Baghouse	BACT-PSD

5.3 FORMATION OF SO_2

Sulfur dioxide (SO_2) is formed either during fuel combustion or from oxidation of pyrite/marcasite (sulfide) and organic sulfur in the kiln. The relative amounts of sulfur in the feed and fuel, the system design, the chemical form of the input sulfur, and the process conditions, such as the presence of an oxidizing or reducing atmosphere in the kiln, are the variables that determine the quantity of SO_2 emissions at any given time. The sulfur content of both raw materials and fuels varies from plant to plant and with geographic location. However, the alkaline nature of the cement provides for direct absorption of SO_2 into the product, thereby mitigating the quantity of SO_2 emissions in the exhaust stream. Depending on the process and the source of the sulfur, SO_2 absorption ranges from about 70 percent to more than 95 percent.

5.4 AVAILABILITY AND EVALUATION OF SO_2 CONTROL TECHNOLOGIES

Available SO_2 control technologies include inherent dry scrubbing, raw feed sulfur reduction, use of alternative fuels, lime spray drying, wet lime scrubbing, and dry lime scrubbing.

As part of the CD agreement that NCC entered with the EPA in 2017, NCC was required to meet an emission limit for each kiln of 1.1 lb SO_2/ton clinker (30-day rolling average) or 294.4 tpy total SO_2. As discussed in the introduction, NCC has installed the capability to inject dry sorbent (lime) for additional SO_2 control other than utilizing process controls. NCC only operates the Dry Sorbent Injection (DSI) System (dry lime scrubbing) on an as needed basis. NDEP has requested that NCC perform a 4FA for full time operation of the DSI system and none of the other potential controls identified and listed above.

5.4.1 DRY SORBENT INJECTION (DSI)

In a DSI system also known as dry lime scrubbing (DLS), dry $CaCO_3$ or $Ca(OH)_2$ is injected into an internal process gas stream. Solid particles of $CaSO_3$ or $CaSO_4$ are produced, which are removed from the gas stream along with excess reagent by a PM control device already in the process flow. The SO_2 removal efficiency of DSI varies widely depending on the point of introduction into the process according to the temperature, degree of mixing, and retention time.

It should be emphasized that the DSI is only applicable to SO_2 concentrations in the stack gases after the inherent SO_2 scrubbing capacity of the cement pyroprocess has been applied. The overall improvement in SO_2 removal is not very high. As discussed, NCC operates the DSI system on an as needed basis, to date when the DSI system has been operational NCC has seen an average control efficiency of approximately 30%. NCC has prepared an analysis for DSI operating 8,760 hr/yr with control efficiencies ranging from 25% to 50% control.

5.4.1.1 Economic Impacts

The capital and annual costs summary for DSI for each kiln (Kiln 1 & Kiln 2) are presented in **Table 5-2** and **Table 5-3**. The actual capital cost to install the currently operating "as needed" DSI system was over \$2.2 million. It should be noted that NDEP directed NCC to not use the \$2.2 million capital cost to install the currently operating as needed DSI system in this cost effectiveness analysis as the DSI system is already operational. The NDEP further indicated the only costs that should be used are the additional annual costs required to operate the DSI system 8,760 hr/yr. However, we have included some capital costs that will be necessary for the DSI system to operate 8,760 hr/yr. Based on NCC's operating experience, the existing DSI system must be upgraded to operate properly on this full-time basis. These upgrades consist of replacing the existing 200 feet of four (4) inch stainless delivery pipe for each kiln's DSI system with 200 feet of six (6) inch stainless delivery pipe to eliminate the plugging issues NCC is currently experiencing when only operating the DSI system as needed. In addition, a new 50 horsepower blower for the larger pipe delivery system and new airlocks for feed rate control must also be installed for each of the kilns' DSI systems. Each kiln is identical and rated at 30.55 ton CL/hr, direct-fired long-dry rotary kiln (coal and pet coke). The capital cost for 200 feet of 6-inch stainless steel for one kiln is \$163,000, while the new blower cost is \$35,000 and airlocks are \$5,400. Total installed capital cost is \$293,687 per kiln.

Total annualized costs are shown in **Table 5-3**. Costs were prepared for control efficiencies between 25% and 50% (25%, 30%, 40%, and 50%). Based on NCC's current operational history of the existing DSI systems on each kiln, NCC believes it is unlikely that greater than 30% control efficiency could be obtained. Tons per year of SO_2 removed range from 36.8 tpy at 25% control to 73.6 tpy at 50% control. As shown in **Table 5-3**, annualized costs are over \$1.3 million per kiln. Annualized costs for DSI include significant reagent (lime) consumption, utilities (electricity, CEMs operating costs, etc.), parts and maintenance, and labor costs for technicians to operate, monitor, and maintain the DSI system operating controls. Operating and maintenance labor is estimated at 1 hour per shift. Lime reagent requirements, based on NCC's actual operating experience over the past year, are 0.56 tons per hour (ton/hr) per kiln at \$217.50/ton equate to approximately \$1.1 million total per kiln (EMI 2020). Electricity costs for the blower are over \$19,000 per kiln (1 compressor/kiln at 50 hp each).

Total cost effectiveness ranges from \$36,500 per ton (\$/ton) at 25% control level to \$18,250/ton at 50% control per kiln, which are clearly excessive.

5.5 FACTOR 2 – TIME NECESSARY FOR COMPLIANCE

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Therefore, compliance deadlines must consider the time necessary for compliance by setting a compliance deadline that provides a reasonable amount of time for the source to implement the control measure.

NCC has indicated that a minimum of 4 months is required to procure, build, install, and "shakedown" the new equipment for proper engineering for the upgrade to a single DSI system (EMI 2020). Notably, the estimated timeframe does not account for time needed for NDEP to develop and implement the regulations, nor the amount of time needed for EPA to take proposed and final action to approve NDEP's SIP.

5.6 FACTOR 3 - ENERGY AND NON-AIR ENVIRONMENTAL IMPACTS

The primary purpose of the environmental impact analysis is to assess collateral environmental impacts due to control of the regulated pollutant in question. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal.

5.6.1 ENERGY IMPACTS

The use of DSI full time (8,760 hr/yr) will have an energy penalty in terms of electricity needed to operate the larger blower (50 hp). The electricity requirement for the DSI system is approximately 39 kW per hour (343,889 kW/yr) which equates to $19,051 per year.

5.6.2 ENVIRONMENTAL IMPACTS

Kiln 1 and Kiln 2 are currently equipped with an as needed DSI system for SO_2 control. The lime reagent used in a DSI system reacts with SO_2 in the flue gas to form calcium sulfate and calcium sulfite solids. The solids are captured in the existing fabric filter particulate control systems and either returned to the systems for reuse or removed from the systems as nonhazardous solid waste. Collateral environmental impacts associated with the DSI system include increased solid waste generation. Additionally, the operation of the DSI storage vessel's baghouse will emit an additional 0.2 tpy of PM (lime) emissions.

5.7 FACTOR 4 – REMAINING USEFUL LIFE OF SOURCE

The evaluation of technically feasible SO_2 control options should consider the source's "remaining useful life" in determining the costs of compliance. The remaining useful life is the difference between the data that controls would be put in place and the date that the facility permanently ceases operation. If the remaining useful life of the unit is shorter than the useful life of a particular control option, the remaining useful life should be used annualizing costs. If the remaining useful life exceeds the useful life of the control options, the remaining use life has no effect on the cost evaluation.

The remaining useful lifetime of both Kiln 1 and Kiln 2 is expected to be longer than the projected lifetime of the pollution control technology (DSI) which has been analyzed for these sources. As such the remaining useful life of the kilns does not impact the annualized costs of DSI because the remaining useful life of both kilns is anticipated to be at a minimum as long as the capital cost recovery period, which is 20 yrs.

5.8 CONCLUSION

The 4FA analysis prepared for NCC SO_2 reductions indicates that the DSI control option is cost prohibitive for Kiln 1 and Kiln 2. At a cost effectiveness ranging from $36,500 to $18,250/ton of SO_2 removed for Kiln 1 and Kiln 2, DSI clearly is not a cost-effective control technology. Although control efficiencies between 25% and 50% were reviewed, based on actual operating experience NCC firmly believes it is unlikely that greater than 30% control efficiency could be obtained on the kilns. Extremely high reagent (lime) cost is the primary contributor to the high cost. DSI is not considered a cost-effective control technology for either of the cement kilns.

In addition, as stated previously, NCC disagrees with the NDEP's statement that the cost for controls that are currently installed should not be included in the analysis. NCC only installed lime injection for the NO_x control project. Had NCC not chosen the catalytic bag filter NO_x control technology, NCC would not have installed the lime injection system since the facility has been able to manage compliance with the state permit limit on a short-term basis and would have used operational controls to ensure the CD limit was met on a 30-day rolling average. Including the $2.2 million capital cost in the analysis results in a cost effectiveness ranging from $53,990/ton at 25% control level to $26,990/ton at 50% control per kiln, which clearly are not cost-effective.

NCC has determined that the only cost-effective and viable control technology for Kiln 1 and Kiln 2 is the existing control option that consists of utilizing existing process controls, inherent dry scrubbing, and DSI on an as needed basis.

Table 5-2 – Dry Sorbent Injection (DSI) Capital Costs – Kiln 1 & Kiln 2

DIRECT COSTS (DC):	
(1) Purchased Equipment Costs:	
(a) Basic Equipment and Auxiliaries (A)	$203,525
(b) Instrument and Controls [0.1 (a)]	$0
(c) Freight [0.05 (a)]	$10,176
(d) Taxes [0.06 (a)]	$12,212
Total Equipment Cost (B)	$225,913
(2) Direct Installation Costs	
(a) Foundations and Supports [0.04 (B)]	$0
(b) Erection and Handling [0.5(B)]	$0
(c) Electrical [0.08 (B)]	$0
(d) Piping [0.01 (B)]	$0
(e) Insulation [0.07 (B)]	$0
(f) Painting [0.02 (B)]	$0
Total Direct Installation Costs	$0
Total Direct Costs, TDC (B + Direct Installation Costs)	$225,913
INDIRECT COSTS (IDC):	
(4) Engineering and Supervision [0.10 (B)]	$0
(5) Construction and Field Expenses [0.20 (B)]	$0
(6) Construction Fee [0.10 (B)]	$0
(7) Start-up [0.02 (B)]	$0
(8) CEMS	$0
(9) Performance Test [0.03 (B)]	$0
Total Indirect Costs, TIDC	$0
Total Direct Costs + Total Indirect Costs	$225,913
Contingency (30% of TDC + TIDC)	$67,774
TOTAL INSTALLED CAPITAL COSTS (TCC)	**$293,687**

Sources: USEPA 2020; Vatavuk and Neveril 1980; Eagle Materials, Inc. 2020 (EMI 2020)

Table 5-3 – Dry Sorbent Injection (DSI) Annualized Costs – Kiln 1 & Kiln 2

DIRECT COSTS:	Percent Control			
	25%	30%	40%	50%
(1) Operating Labor: [1 hr/shift, 3 shifts/day @ $39.61/hr] (C)	$40,416	$40,416	$40,416	$40,416
(2) Supervisory Labor [0.15 (C)]	$6,062	$6,062	$6,062	$6,062
(3) Maintenance Labor: [1 hr/shift, 3 shifts/day @ $45.83/hr]	$50,184	$50,184	$50,184	$50,184
(4) Parts and Materials [100 percent of maintenance labor + 0.10(A)]	$70,536	$70,536	$70,536	$70,536
(5) Utilities				
(a) Electricity ($0.0554/kW-hr, 39 kW, 8,760 hr/yr)	$19,051	$19,051	$19,051	$19,051
(b) CEMS Operating Costs (includes annual RATA)	$22,000	$22,000	$22,000	$22,000
(6) Lime Reagent (0.56 ton/hr, 8,760 hr/yr, $217.5/ton)	$1,058,500	$1,058,500	$1,058,500	$1,058,500
Total Direct Costs	$1,266,751	$1,266,751	$1,266,751	$1,266,751
INDIRECT COSTS:				
(8) Overhead [0.80 (1.15C + 0.04 TDC)]	$44,412	$44,412	$44,412	$44,412
(9) Property Tax (0.01 TCC)	$2,937	$2,937	$2,937	$2,937
(10) Insurance (0.01 TCC)	$2,937	$2,937	$2,937	$2,937
(11) G&A Charges (0.02 TCC)	$5,874	$5,874	$5,874	$5,874
(12) Capital Recovery (CRF * TCC)	$20,199	$20,199	$20,199	$20,199
(a) Capital Recovery Factor (CRF) [3.25% ROR, 20-year life]	0.06878	0.06878	0.06878	0.06878
Total Indirect Costs	$76,359	$76,359	$76,359	$76,359
TOTAL ANNUALIZED COSTS	**$1,343,110**	**$1,343,110**	**$1,343,110**	**$1,343,110**
Tons/year of SO_2 Removed from Both Kilns	36.8	44.2	58.9	73.6
COST EFFECTIVENESS ($/ton SO_2 removed)	**$36,500**	**$30,420**	**$22,810**	**$18,250**

Sources: USEPA 2020; Vatavuk and Neveril 1980; Eagle Materials, Inc. 2020 (EMI 2020)

6. SUMMARY AND CONCLUSIONS

At the request of NDEP, a 4FA for control of SO_2 emissions was prepared for NCC's Kiln 1 and Kiln 2 for use in their Round II Determination. The analysis identified technically feasible SO_2 control options for the kilns, but at the request of NDEP was only evaluated for DSI operating at 8,760 hr/yr for the following four statutory factors:

1. The costs of compliance;
2. The time necessary for compliance;
3. The energy and non-air quality environmental impacts of compliance; and
4. The remaining useful life of any potentially affected anthropogenic source of visibility impairment.

The cost of compliance evaluation (Statutory Factor 1) prepared for SO_2 controls indicates that, from baseline emission rates, the average annual cost effectiveness of DSI operating at 8,760 hr/yr for Kiln 1 and Kiln 2 ranges from \$36,500/ton (25% control) to \$18,250/ton SO_2 removed (50% control) from baseline emissions.

The time necessary for compliance for the SO_2 control options is approximately 8 months.

An evaluation of energy impacts and non-air environmental impacts (Statutory Factor 3) indicates that the use of DSI will have an energy penalty in terms of electricity needed to operate the DSI system. Collateral environmental impacts include increased solid waste generation.

Regarding remaining useful life (Statutory Factor 4), the remaining useful lifetime of both Kiln 1 and Kiln 2 is expected to be longer than the projected lifetime (20 years) of the pollution control technology (DSI) which has been analyzed for these sources. Therefore, the remaining useful life has no impact on the annualized cost of control under the current regulatory framework.

The 4FA prepared for NCC's SO_2 reductions indicates that DSI control operating 8,760 hr/yr is cost prohibitive. The control cost evaluation indicates that the average cost effectiveness levels exceed \$18,250/ton SO_2 removed at 50% control which will likely not be achieved. When a likely 30% efficiency is considered, the cost effectiveness is a much higher \$30,420/ton SO_2 removed. NCC is proposing that the existing control option consisting of utilizing existing process controls, inherent dry scrubbing, and DSI on an as needed basis on Kiln 1 and Kiln 2 represent appropriate controls for the Round II Determination, therefore no change to the current Title V Operating Permit is proposed for SO_2 emissions at NCC.

Finally, NCC disagrees with the NDEP's statement that the cost for controls that are currently installed should not be included in the analysis. As stated previously, NCC only installed lime injection for the NO_x control project. Had NCC not chosen the catalytic bag filter NO_x control technology, NCC would not have installed the lime injection system since the facility has been able to manage compliance with the state permit limit on a short-term basis and would have used operational controls to ensure the CD limit was met on a 30-day rolling average. As a result, the \$2.2 million of capital cost NCC incurred was not included in this analysis thus skewing the analysis putting NCC at an economic disadvantage to other cement plants conducting a similar analysis. Including the \$2.2 million capital cost in the analysis results in a cost effectiveness of \$26,990/ton and \$44,990/ton of SO_2 removed at 50% and 30% control, respectively.

7. REFERENCES

Eagle Materials, Inc. (EMI) 2020. Personal communication between J. Christopher (SLR), E. Dutcher (NCC) and J. Marini (Eagle Materials, Inc. – NCC's parent company) via multiple emails and phone conversations. September 24, 2020, October 5, 2020, October 6, 2020, October 13, 2020.

Grant, E. L., Ireson, W. G., and Leavenworth, R. S. Principles of Engineering Economy, Eighth Edition, John Wiley & Sons, New York, 1990.

Nevada Cement Company (NCC). 2020. Letter from Eric Dutcher (NCC) to Sig Jaunarajs (NDEP) responding to NDEP letter from Sig Jaunarajs dated August 12, 2019. January 9, 2020.

Perry, Robert. H. and Chilton, Cecil. H., editors. 2008. *Perry's Chemical Engineers Handbook*. 8th Edition. McGraw-Hill.

United States Environmental Protection Agency (USEPA). 2017. Office of Air Quality Planning and Standards Control Cost Manual. Office of Air Quality Planning and Standards, Economic Analysis Branch, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. November. (Chapter 2, updated November 2017)

_____. 2020. BACT/RACT/LAER Clearinghouse - Compilation of Control Technology Evaluations. (October 6, 2020)

Vatavuk, W. M. and Neveril, R. B. "Estimating Costs of Air Pollution Control Systems - Part I: Parameters for Sizing Systems," Chemical Engineering. October 6, 1980, pp 165-168.

Appendix B.4.c - Response Letter 1

NEVADA CEMENT COMPANY, LLC
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November 12, 2020

Sig Jaunarajs
Supervisor, Planning and Mobile Sources Branch
Bureau of Air Quality Protection
Nevada Division of Environmental Protection (NDEP)
901 S. Stewart St., Suite 4001
Carson City, NV 89701

Re: Regional Haze Four Factor Analysis SO_2
Nevada Cement Company
Response to NDEP Comments – email Dated November 3, 2020

Dear Mr. Jaunarajs:

Nevada Cement Company (NCC) has received your email dated November 3, 2020 and reviewed the NDEP-BAPC's request for additional information. Following are NCC's responses to the additional information you have requested in the referenced email. Where necessary, additional information is attached to this letter and reference accordingly. Please consider this letter and attachments an official response to your request for additional information. For ease of review, the heading and item number/comment is listed below followed by our response.

Comment 1

DSI Baseline Operation - Please develop a baseline scenario of what the DSI system is currently being operated at to achieve the 1.1 lb/ton clinker emission limit (annual hours its been operated at). When calculating the cost of operating the control at a higher capacity, this should be conducted incremental to the baseline scenario.

Respond to Comment 1

We have updated our annualized cost table (Table 2) to reflect Kiln #1 and Kiln #2 actual operating hours using a 10-year look back period and what could have been accommodated. Attachment A provides both Table 1 and Table 2 for ease of review. For Kiln #1 this is based on the year 2013 and results in 7,953 hours per year (hr/yr). For Kiln #2 this is based on the year 2015 and results in 7,850 hr/yr. These hours are consistent with NCC's most recent PSD applicability analysis conducted for the Finish Mill #4 project reviewed and approved by the NDEP.

In addition, we have recalculated the annual emissions for each kiln based on the operating hours used for developing the capacity factor. NCC began tracking the operation of the DSI system in 2020 and has evaluated how many hours each kiln operated the respective DSI system in 2020 to date (January 1, 2020 to November 2, 2020). For Kiln #1 the DSI system operated 14.26% of the time, and Kiln #2 operated 19.06% of the time. Using Kiln #1 as an example:

- (1.1 lb SO_2/ton CL) (30.55 ton CL/hr) = 33.61 lb SO_2/hr
- (33.61 lb SO_2/hr) (7,953 hr/yr) (ton/2,000 lb) = 133.6 tpy SO_2
- (133.6 tpy SO_2) (100-14.26) / (100) = 114.6 tpy SO_2

The 114.6 tpy SO_2 emission rate is the baseline emission rate that Kiln #1 operated without DSI.

- (114.6 tpy SO_2) (0.30) = 34.4 tpy SO_2

At 30% control, an additional 34.4 tpy SO_2 will be reduced using the DSI system full time.

Comment 2

Application of Capacity Factor - In the table provided below, we have the following annual operating hours for each kiln over the past few years. Rather than calculating components like additional lime reagent and electricity at 8,760 hours, please apply a capacity factor to each kiln that will reflect the annual operating hours that have been recorded in the past. This may have been due to unclear instructions on our part, so I apologize if we caused this confusion. To summarize, the additional annual hours used to evaluate costs should consist of capacity factor hours minus the baseline scenario hours.

Year	Kiln 1 Annual Hours	Kiln 2 Annual Hours
2016	6281	6659
2017	4594	7184
2018	7606	7569
2019	6367	6557

Respond to Comment 2

As shown in Table 1 and Table 2 of Attachment A, we have updated our annualized costs to list the capacity factor for each kiln based on the above actual annual hours of operation. The capacity factor is listed in the table and each row of cost data has subsequently been multiplied by the capacity factor. The capacity factor for Kiln #1 is 0.9079 and for Kiln #2 is 0.8962. It should be noted that the capacity factor has not been applied to the electricity or lime reagent costs, as these calculations are based on the actual additional hours (incremental) the electricity and lime will be used. For Kiln #1 and Kiln #2 this equates to:

Kiln	Lime Operating Hours	Lime Non-Operating Hours
1	(7,953 hr/yr) (0.1426) = 1,134 hr/yr	(7,953 hr/yr) – (1,134 hr/yr) = 6,819 hr/yr
2	(7,850 hr/hr) (0.1906) = 1,496 hr/yr	(7,850 hr/hr) – (1,496 hr/yr) = 6,354 hr/yr

Comment 3

Lime Rate and Price - Please provide documentation that supports the assumed lime rate of 0.56 tons/hr and lime price of $217.50/ton.

Respond to Comment 3

When lime is being used continuously in each kiln, on average we use a truck load of lime (40 ton capacity truck) in three (3) days.

- (40 ton / 3 days) (day / 24 hr) = 0.56 ton/hr

Attachment B provides two invoices representing the delivery price of lime/ton ($63/ton) and the price of lime/ton ($154.50/ton), equating to a total price of $217.50/ton lime delivered to the plant.

Comment 4

Parts and Materials - The equation used to calculate the cost of parts and materials is overgeneralized. I didn't find a section of the CCM methodology chapter that supports this, especially for an existing system. Costs for parts and materials should be more specific and itemized.

Respond to Comment 4

The equation is not based on an existing system. The equation is based on the new capital costs for the 200 feet of new 6-inch stainless steel pipe, new larger blower, and new air locks for feed rate control. All of which will need to be replaced within 5 years based on wear rates at other facilities using DSI, not to mention

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general maintenance that will occur. The equation is taken from Page 2-50 of the Cost Control Manual as follows:

> *"The labor costs are a function of the level of automation. Less labor is required for automatic controls but there are significantly higher capital costs for fully automated scrubber systems. Venturi scrubbers are assumed to require 2 to 8 hours of operating labor per shift [12]. More labor hours may be required for systems with highly variable flow rates, temperatures, or pressures. Supervisory labor is assumed to be 15% of the operating labor and maintenance labor per shift, approximately 1 to 2 hours.* ***The cost of materials required for maintenance is assumed to 100% of the maintenance labor cost****. [12]"*

In addition, it should be noted that we have included an additional cost for replacing the 200 feet of 6-inch piping. The piping will need to be replaced every five (5) years, and we have added this cost to the annualized costs. The total cost of 200 feet of 6-inch piping is $163,125. The annualized replacement costs for the piping is $35,874 and is based on a 5-yr life. The cost has been annualized based on a five-year life and 3.25 percent rate of return.

Comment 5

CEMS operating costs - It is to our understanding that NV Cement is required to operate CEMS regardless of this analysis. If this is the case, please omit this from the cost calculation.

Respond to Comment 5

Yes, you are correct. We have eliminated this cost from the calculations.

Please find attached updated capital and annualized cost tables for DSI for each kiln. We trust the information described in detail above provides the NDEP with sufficient information to complete your review of DSI for SO_2 control on each of NCC's kilns. Should you have any questions or require more information, please contact me at (775) 575-2281 ext. 204 or via email at edutcher@nevadacement.com.

Sincerely,

Eric Dutcher
Environmental Manager
Nevada Cement Company

Cc: Joseph Marini – Eagle Materials, Dallas, TX
Jamie Christopher – SLR, Fort Collins, CO

ATTACHMENT A - Updated Capital & Annualized Costs

Table 1 – DSI Capital Costs (Per Kiln)
Table 2 – DSI Annualized Costs (Per Kiln)

Table 1 Nevada Cement Company
Dry Sorbent Injection Capital Costs (Per Kiln)

DIRECT COSTS (DC):	
(1) Purchased Equipment Costs:	
(a) Basic Equipment and Auxiliaries (A)	$203,525
(b) Instrument and Controls [0.1 (a)]	$0
(c) Freight [0.05 (a)]	$10,176
(d) Taxes [0.06 (a)]	$12,212
Total Equipment Cost (B)	$225,913
(2) Direct Installation Costs	
(a) Foundations and Supports [0.04 (B)]	$0
(b) Erection and Handling [0.5(B)]	$0
(c) Electrical [0.08 (B)]	$0
(d) Piping [0.01 (B)]	$0
(e) Insulation [0.07 (B)]	$0
(f) Painting [0.02 (B)]	$0
Total Direct Installation Costs	$0
Total Direct Costs, TDC (B + Direct Installation Costs)	$225,913
INDIRECT COSTS (IDC):	
(4) Engineering and Supervision [0.10 (B)]	$0
(5) Construction and Field Expenses [0.20 (B)]	$0
(6) Construction Fee [0.10 (B)]	$0
(7) Start-up [0.02 (B)]	$0
(8) CEMS	$0
(9) Performance Test [0.03 (B)]	$0
Total Indirect Costs, TIDC	$0
Total Direct Costs + Total Indirect Costs	$225,913
Contingency (30% of TDC + TIDC)	$67,774
TOTAL INSTALLED CAPITAL COSTS (TCC)	**$293,687**

Sources: USEPA 2020; Vatavuk and Neveril 1980; Eagle Materials, Inc. 2020 (EMI 2020)

Table 2 Nevada Cement Company
Dry Sorbent Injection Annualized Costs (Per Kiln)

		Kiln #1	Kiln #2
DIRECT COSTS:			
	Percent Control	**30%**	**30%**
	Capacity Factor	**0.908**	**0.896**
(1) Operating Labor: [1 hr/shift, 3 shifts/day @ $39.61/hr] (C)		$36,693	$36,218
(2) Supervisory Labor [0.15 (C)]		$4,997	$4,868
(3) Maintenance Labor: [1 hr/shift, 3 shifts/day @ $45.83/hr]		$45,561	$44,971
(4) Parts and Materials [100 percent of maintenance labor + 0.10(A)]		$64,038	$63,209
(4a) 5-Yr Piping Replacement Costs (3.25% Interest, 5 years, CRF = 0.21992, $163K)		$35,874	$35,874
(5) Utilities			
(a) Electricity ($0.0554/kW-hr, 39 kW, 6,819 hr/yr [K1] & 6,354 hr/yr [K2])		$14,830	$13,818
(6) Lime Reagent (0.56 ton/hr, $217.5/ton, 6,819 hr/yr [K1] & 6,354 hr/yr [K2])		$823,951	$767,750
Total Direct Costs		$1,025,943	$966,708
INDIRECT COSTS:			
(8) Overhead [0.80 (1.15C + 0.04 TDC)]		$37,211	$36,337
(9) Property Tax (0.01 TCC)		$2,666	$2,632
(10) Insurance (0.01 TCC)		$2,666	$2,632
(11) G&A Charges (0.02 TCC)		$5,333	$5,264
(12) Capital Recovery (CRF * TCC)		$18,339	$18,101
(a) Capital Recovery Factor (CRF) [3.25% ROR, 20-year life]		0.06878	0.06878
Total Indirect Costs		$66,215	$64,966
TOTAL ANNUALIZED COSTS		**$1,092,158**	**$1,031,673**
Tons/year of SO_2 Removed from Both Kilns		34.4	32.0
COST EFFECTIVENESS ($/ton SO_2 removed)		**$31,770**	**$32,210**

Sources: USEPA 2020; Vatavuk and Neveril 1980; Eagle Materials, Inc. 2020 (EMI 2020)

ATTACHMENT B - Cost of Lime Delivered to the Plant (supporting invoices)

Lhoist North America
Lhoist Group

ORIGINAL

Remit To:
Lhoist North America of Arizona, Inc.
5230 Paysphere Circle
Chicago , IL - 60674
(800) 365-6724

Invoice
1102027034 10/20/2020
Billing reference
307763668 10/20/2020
Sold-to Customer 160199
NEVADA CEMENT COMPANY
ATTN ACCOUNTS PAYABLE
Contract Number
0070158270
Payer 160199

Bill-to: Customer No 160199
NEVADA CEMENT COMPANY
ATTN ACCOUNTS PAYABLE
1290 WEST MAIN ST
FERNLEY NV 89408-7756

Payment Terms:
Payment due on or before 11/19/2020
Net Due 30 Days After Invoice

Currency: USD

Item	Date	BOL No Ref No	Mat No	Material Description / Packaging	Qty	UoM	Unit Price	Amount	Tax
1	10/09/2020	4061208		PO Number: 123424 Shipping point: APEX Means of transport: Truck					
			Ship-to:	320625 / NEVADA CEMENT FERNLEY 1290 WEST MAIN ST / FERNLEY NV 89408-7756					
			1155	Hydrated Lime - Hi Cal / Bulk	19.590	TON	154.50	3,026.66	
Total	10/09/2020	4061208			19.590			3,026.66	
2	10/09/2020	4061209		PO Number: 123424 Shipping point: APEX Means of transport: Truck					
			1155	Hydrated Lime - Hi Cal / Bulk	16.430	TON	154.50	2,538.44	
Total	10/09/2020	4061209			16.430			2,538.44	

ITEM SUMMARY:

Mat No	Description	Qty	UoM
1155	Hydrated Lime - Hi Cal	36.020	TON

Sub Total	5,565.10
Tax	395.12
Total Due	5,960.22

CYCLONE TRANSPORT LLC.
PO 1296
FERNLEY NV 89408

Invoice

Date	Invoice
9/17/2020	13962

Bill To
NEVADA CEMENT COMPANY 1290 W. Main st FERNLEY, NV 89408-0840

joy.cyclonetransport.com

P.O. No.	Terms	Truck Tag
123424	Net 15	20 58934

Item	Description	QTY	Rate	Amount
NCC-LHOIST	LHOIST HYDRATE-LIME FROM APEX PLANT-2041177,2041176	42.68	63.00	2,688.84

Phone : 775 575 5885

Total	2,688.84
Payments/Credits	0.00
Balance Due	2,688.84

TRANSPORTATION ONLY
70403.141 SM

Appendix B.4.d - Response Letter 2

NEVADA CEMENT COMPANY, LLC
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January 12, 2021

Steven McNeece
Environmental Scientist
Nevada Division of Environmental Protection (NDEP)
901 S. Stewart St., Suite 4001
Carson City, NV 89701

Re: Regional Haze Four Factor Analysis SO_2
Nevada Cement Company
Response to NDEP Comments – email Dated January 7, 2021

Dear Mr. McNeece:

Nevada Cement Company (NCC) has received your email dated January 7, 2021 and reviewed the NDEP-BAPC's request for additional information. Following are NCC's responses to the additional information you have requested in the referenced email. Where necessary, additional information is attached to this letter and reference accordingly. Please consider this letter and attachments an official response to your request for additional information. For ease of review, the heading and item number/comment is listed below followed by our response.

Comment 1 - Contingency Factor

A contingency factor of 30% is excessive for a project that is simply replacement of pipes of blowers. The Control Cost Manual states:

"A contingency factor should be reserved (and applied to) only those items that could incur a reasonable but unanticipated increase but are not directly related to the demolition, fabrication, and installation of the system. For mature control technologies, which reflect the control technologies covered in the other chapters of this Manual, the contingency can range from 5 to 15% of the TCI."

Considering the suggested contingency range in the CCM and simple replacement of pipes and blowers, NDEP finds that a contingency factor no larger than 5% is reasonable. Should Nevada Cement want to use a larger contingency factor, please provide source-specific data and documentation that support a higher contingency factor.

Respond to Comment 1

For conservatism, we have updated our capital cost table (Table 1) to reflect a 5% contingency. Please find the updated Table 1 in Attachment A.

Comment 2 – DSI Piping 5-Year Life

A 5-year life for delivery piping and blowers does not agree with other cost analyses conducted for DSI. Among other 4-factor analyses submitted, Sargent & Lundy (the developer of the IPM model for DSI costs) assumes at least 20 years. If the 5-year assumption is based off experience in a similar setting, please explain and document the case in which the life of the piping system and blowers were 5 years and why this scenario would apply to the Fernley Plant kilns. If it is a concern of clogging, please explain in detail why the new, larger, 6" piping would not be capable of lasting beyond 5 years and why larger piping, beyond 6", would not fix this issue.

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Respond to Comment 2

The life of the pipe is not a clogging concern, rather a wear issue. Regardless, we have updated our annualized cost table (Table 2) to reflect a 20-year life. The updated Table 2 is provided in Attachment A.

<u>Comment 3 – Property Tax</u>

Per Nevada state law (NRS 361.077), "All property, both real and personal, 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." Please omit property taxes from your calculations.

Respond to Comment 3

The property tax has been removed from our annualized cost table (Table 2). Please find the updated Table 2 in Attachment A.

<u>Comment 4 – Baghouse Recycling</u>

Considering the low 30% control efficiency estimate for DSI and high reagent costs, can reagent costs be reduced by recycling the baghouse dust with the unreacted lime?

Respond to Comment 4

Tests have been done at other Portland cement plants, but it is the high calcium carbonate that reacts with the SO_2. NCC's sister plant operating in Texas attempted to use their baghouse dust but the calcium carbonate is less than 50% and as a result you cannot get the same control and the baghouse ends up being overloaded (very high pressure drop) trying to achieve the reduction. When operating at higher than normal pressure drops, the bags become stressed and do not function as they were designed and emit more particulate matter emissions. Therefore, we do not believe this is a viable option.

<u>Comment 5 – DSI 20-Year Cost Recovery Period</u>

According to the recently updated proposed SO_2 controls chapter of the Control Cost Manual, DSI is "not a stand-alone, add-on air pollution control system but a modification to the combustion unit or ductwork." NCC has chosen to analyze 20 years for the "cost recovery period" (p.16), but notes that the useful life of both kilns is anticipated to be at a minimum as long as that. If this control is a modification to the kiln's ductwork, it does not appear to be reasonable to have a useful life shorter than the expected life of the kiln. On p.11, NCC notes that cement kilns have a design life of 50 years, which can be extended. Please derive a new cost recovery period based on the remaining useful life of the kilns and use this value for the cost recovery period.

Respond to Comment 5

20 years is based on generally accepted accounting practices and NCC considers these to be acceptable for this analysis since they are prescribed by the federal government. However, since you requested that we perform the analysis assuming 50 years, we ran the numbers and the outcome was a reduction of only $200/ton for each kiln. Since the 50 years is not aligned with the generally accepted accounting practices for depreciation, we have not provided this information in this request.

<u>Comment 6 – DSI Control Efficiency</u>

The new SO_2 controls chapter states that "DSI can achieve SO_2 control efficiencies ranging from 50 to 70%." Please evaluate control efficiencies up to 70%. In determining the likely control efficiency of DSI on the Fernley Plant kilns (currently assumed at 30%), please document how that control efficiency was derived based on kiln-specific design parameters. If the assumed control efficiency is based on another facility, please compare the difference between the kiln's design parameters, specifically, parameters that influence DSI control efficiency.

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Respond to Comment 6

During the installation of the lime injection system, NCC worked with the vendor to identify the optimal location for lime injection since temperature and residence time has a large effect on the ability for the lime to react with the SO_2. NCC went back to evaluate the actual emission reductions that were achieved on the kiln systems during the periods when lime was injected, and a summary of the data is provided below. Based on this information, NCC's control efficiency is highly variable between no reduction and almost 50%. Because of this, we felt the 30% was substantiated as it was the overall average of these runs.

K1 (7/19-20/2020) – 21.57 lb/hr before control, 14.27 lb/hr while running until shut off a 33.84% reduction

K1 (8/29-31/2020) - 14.01 lb/hr before control, 19.83 lb/hr while running until shut off - ***NO*** *reduction*

K1 (9/5-6/2020) – 23.97 lb/hr before control, 19.29 lb/hr while running until shut off a 19.52% reduction

K2 (7/28/2020) – 15.76 lb/hr before control, 16.60 lb/hr while running until shut off - ***NO*** *reduction*

K2 (8/17/2020) – 27.89 lb/hr before control, 14.07 lb/hr while running until shut off a 49.55% reduction

K2 (8/21/2020) – 23.49 lb/hr before control, 17.02 lb/hr while running until shut off a 27.54% reduction

Comment 7 – Cost Estimate Sources

Three sources are listed below each cost estimate table; however, it is unclear which cost figures were provided by which source. Please indicate, for each cost, which source it comes from. For cost estimates provided by Eagle Materials, Inc., the analysis should provide the documentation where the cost figures come from. All quotes from the vendor should be documented, including the emails listed under references as they may be the basis for the cost determinations.

Respond to Comment 7

The Vatavuk and Neveril reference is the basis for the 30% contingency we used. The USEPA reference is also the basis for the 30% contingency that was used along with the cost multipliers used in both the capital and annualized cost tables. Please see Section 4.2.1 "Cost Effectiveness Methodology", Section 4.2.2 "Capital Costs" and Section 4.2.3 "Annualized Costs" of the original Four Factor Analysis submitted for a detailed discussion on this matter.

The Eagle Materials, Inc reference is for the actual Capital Cost Data (Basic Equipment and Auxiliaries), and Annualized Costs (Operating Labor, Maintenance Labor, and Piping Replacement Cost).

Please see Attachment B for the capital cost of the piping, new blower, and new air locks.

Comment 8 – Piping Cost Documentation

The report states that the capital cost for 200 feet of 6-inch stainless steel piping for one kiln is $163,000, while the new blower cost is $35,000 and airlocks are $5,400. Please provide documentation of these cost estimates.

Respond to Comment 8

Please see Attachment B for the capital cost of the piping, new blower, and new air locks. We have highlighted the associated quote prices. Please note that since these quotes were for 4" line and our analysis is for a 6" line, we have scaled the prices assuming the cost would be linear.

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Please find attached updated capital and annualized cost tables for DSI for each kiln. We trust the information described in detail above provides the NDEP with sufficient information to complete your review of DSI for SO_2 control on each of NCC's kilns. Should you have any questions or require more information, please contact me at (775) 575-2281 ext. 204 or via email at edutcher@nevadacement.com.

Sincerely,

Eric Dutcher
Environmental Manager
Nevada Cement Company

Cc: Sigurd Jaunarajs - NDEP
Joseph Marini – Eagle Materials, Dallas, TX
Jamie Christopher – SLR, Fort Collins, CO

ATTACHMENT A - Updated Capital & Annualized Costs

Table 1 – DSI Capital Costs (Per Kiln)
Table 2 – DSI Annualized Costs (Per Kiln)

Table 1 Nevada Cement Company

Dry Sorbent Injection Capital Costs (Per Kiln)

DIRECT COSTS (DC):		
(1)	Purchased Equipment Costs:	
	(a) Basic Equipment and Auxiliaries (A)	$203,525
	(b) Instrument and Controls [0.1 (a)]	$0
	(c) Freight [0.05 (a)]	$10,176
	(d) Taxes [0.06 (a)]	$12,212
	Total Equipment Cost (B)	$225,913
(2)	Direct Installation Costs	
	(a) Foundations and Supports [0.04 (B)]	$0
	(b) Erection and Handling [0.5(B)]	$0
	(c) Electrical [0.08 (B)]	$0
	(d) Piping [0.01 (B)]	$0
	(e) Insulation [0.07 (B)]	$0
	(f) Painting [0.02 (B)]	$0
	Total Direct Installation Costs	$0
Total Direct Costs, TDC (B + Direct Installation Costs)		$225,913
INDIRECT COSTS (IDC):		
(4)	Engineering and Supervision [0.10 (B)]	$0
(5)	Construction and Field Expenses [0.20 (B)]	$0
(6)	Construction Fee [0.10 (B)]	$0
(7)	Start-up [0.02 (B)]	$0
(8)	CEMS	$0
(9)	Performance Test [0.03 (B)]	$0
	Total Indirect Costs, TIDC	$0
Total Direct Costs + Total Indirect Costs		$225,913
Contingency (5% of TDC + TIDC)		$11,296
TOTAL INSTALLED CAPITAL COSTS (TCC)		**$237,208**

Sources: USEPA 2020; Vatavuk and Neveril 1980; Eagle Materials, Inc. 2020 (EMI 2020)

Table 2 **Nevada Cement Company**
Dry Sorbent Injection Annualized Costs (Per Kiln)

		Kiln #1	Kiln #2
DIRECT COSTS:			
	Percent Control	**30%**	**30%**
	Capacity Factor	**0.908**	**0.896**
(1) Operating Labor: [1 hr/shift, 3 shifts/day @ $39.61/hr] (C)		$36,693	$36,218
(2) Supervisory Labor [0.15 (C)]		$4,997	$4,868
(3) Maintenance Labor: [1 hr/shift, 3 shifts/day @ $45.83/hr]		$45,561	$44,971
(4) Parts and Materials [100 percent of maintenance labor + 0.10(A)]		$64,038	$63,209
(4a) 20-Yr Piping Replacement Costs (3.25% Interest, 20 years, CRF = 0.06878, $163K)		$11,220	$11,220
(5) Utilities			
(a) Electricity ($0.0554/kW-hr, 39 kW, 6,819 hr/yr [K1] & 6,354 hr/yr [K2])		$14,830	$13,818
(6) Lime Reagent (0.56 ton/hr, $217.5/ton, 6,819 hr/yr [K1] & 6,354 hr/yr [K2])		$823,951	$767,750
Total Direct Costs		$1,001,289	$942,053
INDIRECT COSTS:			
(8) Overhead [0.80 (1.15C + 0.04 TDC)]		$37,211	$36,337
(9) Property Tax (0.01 TCC) - ***NOT ALLOWED PER NRS 361.077***		$0	$0
(10) Insurance (0.01 TCC)		$2,154	$2,126
(11) G&A Charges (0.02 TCC)		$4,307	$4,251
(12) Capital Recovery (CRF * TCC)		$14,812	$14,620
(a) Capital Recovery Factor (CRF) [3.25% ROR, 20-year life]		0.06878	0.06878
Total Indirect Costs		$58,484	$57,334
TOTAL ANNUALIZED COSTS		**$1,059,773**	**$999,388**
Tons/year of SO_2 Removed from Both Kilns (30% Control Efficiency)		34.4	32.0
COST EFFECTIVENESS ($/ton SO_2 removed)		**$30,830**	**$31,200**

ATTACHMENT B - Cost of DSI System

Piping Quote

BRAHMA
GROUP, INC.

March 27, 2019

Nevada Cement:
Fernley N.V.

Attention: Gavin Patzer

Subject: Dust Tank Conveying Line Project REV. 3/20/19 GSP

BGI Quote Number:

To Whom It May Concern:

Brahma Group, Inc. (BGI) is pleased to furnish you with a ****Budgetary**** cost estimate for above referenced project and location.

Scope of Work:

1. BGI will perform as follows:
   - This proposal is for budgetary use.
   - Reverenced Excel Spread Sheet Preliminary SOW Dust Tank Conveying Line Project REV. 3/20/19 GSP
2. BGI will perform work as directed by Nevada Cement Site Personnel.
3. Nevada Cement to dispose of all materials and waste after project completion.
4. Nevada Cement will provide safe access to the work area through lock out or other means.
5. Nevada Cement will be invoiced 30% upfront upon award of contract.
6. Work is to be performed continuously within duration from Start date. Any delays will be invoiced at the composite rate of for everyone on-site. In the event of long term delays, rental equipment will be invoiced at an additional cost + 10% for the duration of the delay.
7. Quote not valid unless signed and returned to Brahma Group Inc, please send to john.bell@bgi.emal.

Attachment 8

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EB

Inclusions;

1. Mobilization.
2. Transportation.
3. Labor, consumables, and tools to complete all scopes of work.
4. Supervision.
5. Safety equipment and PPE.
6. Demobilization.

Clarifications;

1. BGI work is to be continuous and sequential. Delay or interference outside BGI control will be charged to the Owner's account.
2. BGI assumes all utilities; including, 480 volt, 240 Volt and 110 volt electricity and their hookup, will be provided by Albemarle.
3. BGI assumes all fuel for equipment will be provided by Nevada Cement.
4. Refuse and rubble material will be place in bins provided by Nevada Cement. Disposal of material placed to bins by others.
5. Progress payments to BGI beyond agreed terms will be subject to a 3% charge.
6. Tax of 6.85% is included at the time of agreement, anything purchased, or inadvertently missed in these calculations will be billed accordingly.
7. Price based on what is known of the project at this time. Materials pricing subject to change on the receival of Nevada Cement specs.
8. BGI reserves the right to review all terms, conditions and provisions of any agreement to which Brahma Group Inc. may become bound, assuming this proposal is accepted.
9. Our indirect staffing and general conditions are sized for the known scope, plus or minus 5%.

Exclusions;

1. Excavation
2. Backfill
3. Permitting.

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Pricing:

Brahma Group, Inc. will furnish all the necessary Labor, Tools, Materials, Equipment, and Transportation required to complete the above scope for the following **"Budgetary"**:

Budgetary as stated:

One Hundred Forty Five Thousand Four Hundred Eighteen Dollars & 00/100's

$145,418.00

* * * * * * * * * * *

We thank you for the opportunity to provide you with our quotation and look forward to working with you on this project. Should you have any questions, please do not hesitate to contact us at your convenience.

Best Regards,
Brahma Group, Inc.

John Bell
Nevada Project Superintendent
(775) 385-4352 cell
John.bell@bgi.email

X______________________________
Brahma Representative DATE:

X______________________________
Nevada Cement Representative DATE:

CO
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KD

Blower and Airlock Quote

BALL
SALES & ENGINEERING
17912 Georgetown Lane, Huntington Beach, CA 92647
Tel: (800) 966-1127 | Fax: (714) 596-7399 | www.ballengineering.com | sales@ballengineering.com

QUOTATION

Date: March 26, 2019 *Ref:* 19-0228-B

To: Nevada Cement – Fernley, NV
Gavin Patzer – (775) 575-2281 x204
gpatzer@nevadacement.com

Regarding: Following is our revised (Rev B) budgetary quotation for the equipment you specified for your CKD Pneumatic Conveying System Expansion. Revision A changed the Butterfly Valves to Manual Actuated. This Revision B changed the Blower Package to have a 50-HP Motor.

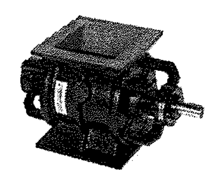
<u>*Application Data:*</u>

Construction: Carbon Steel
Material Description: CKD
Particle Size/Type: Powder
Bulk Density: 48 PCF
Temperature: <250°F

Rate: 6.7 CFM
Inlet Conditions: Hopper
Pressure Above: Atmospheric
Discharge Conditions: Pressure Conveying Line
Pressure Below: <15 PSI

<u>*Item 1*</u>
Qty. one (1) - Meyer 10x10 HDX, Round Flange, Drop Thru Rotary Airlock/Feeder .... $5,261.00 ea.

Specifications:
Cast Iron Housing and Head Plates *(Meyer Standard Paint)*
8-Vane Mild Steel Rotor (0.34 CFR)
Open End, Mild Steel Rotor with Beveled & Relieved Tips & Ends
Machined for up to 250° F Maximum Temperature
Outboard Mounted Bearings; Aluminum Blind End Bearing Cap
Graphite Impregnated Aramid Fiber Packing Gland Shaft Seals
Flange Guard
VFAC Controller Supplied by Others
20-RPM Severe Duty Chain Drive with Cast Iron Reducer *(Vendor Standard Paint)*
Carbon Steel Motor Base Plate *(Meyer Standard Paint)* and ABS Plastic OSHA Guard
1-HP, 230/460V-3PH-60Hz, TEFC, Mild Steel Premium Efficiency Motor *(Vendor Standard Paint)*



<u>*Options for Item 1*</u>
Hard Chrome Coating on Housing Bore and Head Plate Interior Surfaces ....$652.00 adder
Hard Faced (Stellite Material) Rotor Tips & Ends ....$1,897.00 adder
Air Purged Shaft Seals with Cast Iron Lantern Ring...$226.00 adder
Set of Two (2) Silicone Flange Gaskets ....$154.00 adder

Attachment 1D

<u>*Item 2*</u>
Qty. one (1) - Meyer 10x10 Model D Discharge Adapter, 4" SCH40 Pipe Plain Ends, Carbon Steel .... $657.00 ea.

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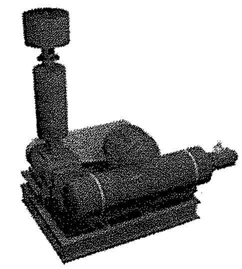
Item 3
Qty. one (1) – Cyclonaire Blower Package...$29,800.00 ea.

Specifications:
283 SCFM @ 6 PSIG at 1,166 RPM
Gardner Denver Duro-Flow (GGDDCCA, Model 4512, LHCCW)
Belt Driven
50-HP, TEFC, 230/460V-3PH-60Hz, 1765-RPM Motor
Inlet Air Filter/Silencer with Replaceable Element
Exhaust Silencer
Safety Relief Valve
Check Valve
Adjustable Motor Base for Correct Belt Tension Setting
Welded, Heavy Duty Carbon Steel Base
Cyclonaire Blue/OSHA Safety Yellow Paint Scheme



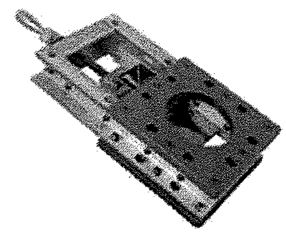
The air supply will develop approximately 180ºF temperature rise due to compression. The average noise level, depending on system application, is 95-110 dB-A scale slow response at 3 feet free field radius. Motor starter and supply hose / pipe are by others.

Options for Item 3
Temperature Switch ....$1,200.00 adder

Item 4
Qty. one (1) – Vortex Model MRHW08-E104017, 8" Round "Keeper" Maintenance Gate ....$1,734.00 ea.

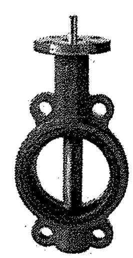
Specifications:
8" x 8" Round Flange Maintenance Gate
Non-rising Manual **Hand Wheel** Actuator**
Graphite Bonnet Seals
Round Pattern Carbon Steel Flanges
304 Stainless Steel Blade *(Self Cleans on Closing Stroke)*
E104017 – Carbon Steel Frame and Covers

*** Note: Valve Takes 5 Cranks per Inch of Blade Travel. Photo shows Hand Crank.*



Item 5
Qty. two (2) – Vortex Model 772300040090000-141198, 4" Wafer Style Butterfly Valve ....$242.00 ea.

Specifications:
4"Ø Opening
Wafer Style Cast Iron Body
17-4 Stainless Steel Disc
17-4 Stainless Steel Stem
Natural Rubber Seat
4" Manual Lever Handle



Item 6
Qty. one (1) – HammerTek Series 400 **90º** Elbow, 4" SCH 40...$1,462.00 ea.

Specifications:
125 # ANSI Flat Face Flange on each end for Elbow to Pipe Connection.
Hard Cast Iron Alloy with a hardness of 380-420 BHN.

Item 7
Qty. one (1) – HammerTek Series 400 **45º** Elbow, 4" SCH 40...$1,547.00 ea.

Specifications:
125 # ANSI Flat Face Flange on each end for Elbow to Pipe Connection.
Hard Cast Iron Alloy with a hardness of 380-420 BHN.

LB
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Lead Time for Shipment: Will Advise
.O.B. Factory IL

Terms: Net 30 Days from Shipment on all Orders up to $10,000.00; 2% Processing Fee for Credit Card Orders
Orders that exceed $10,000.00: ⅓ Down Payment; Balance due 30 days from shipment. Upon Approved Credit.
Quotation firm for 30 days. Budgetary Pricing to be confirmed.

Purchase orders should be made to:
Ball Sales & Engineering Corp. – 17912 Georgetown Lane – Huntington Beach, CA 92647 – (800) 966-1127

Email Purchase Orders to sales@ballengineering.com or Fax to (714) 596-7399.

Thank you for this opportunity to quote our products. If you have any questions, please call or e-mail the salesperson below:

Nick Bruce – nbruce@ballengineering.com Cell (530) 615-1399

BALL SALES AND ENGINEERING
Main Office: (800) 966-1127
www.ballengineering.com

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Appendix B.4.e - NCC Email

FW: Regional Haze

Sig Jaunarajs <sjaunara@ndep.nv.gov>
Fri 9/20/2019 1:10 PM
To: Steven McNeece <smcneece@ndep.nv.gov>

1 attachments (10 KB)
2014 Revised Emission Rate.xlsx;

FYI

Sig Jaunarajs
Supervisor
Planning and Mobile Sources Branch, BAQP
Nevada Division of Environmental Protection
Department of Conservation and Natural Resources
901 S. Stewart Street, Suite 4001
Carson City, NV 89701
sjaunara@ndep.nv.gov
(O) 775-687-9392 | (F) 775-687-5856

Nevada Department of CONSERVATION & NATURAL RESOURCES
Connect with us:

NEVADA DIVISION OF ENVIRONMENTAL PROTECTION

From: Eric Dutcher <edutcher@nevadacement.com>
Sent: Friday, September 20, 2019 11:51 AM
To: Sig Jaunarajs <sjaunara@ndep.nv.gov>; Joseph Marini <Jmarini@eaglematerials.com>; Jamie Christopher <jchristopher@slrconsulting.com>
Subject: Regional Haze

Hi Sig
Please find the attached spreadsheet showing the revised emission rates for 2014. We calculated emission rates using kiln cems data from 2018 that is indicative of the emission rates of the kilns in previous years. We then applied these emission rates to the production rates of the kilns in 2014. This applies for NOx and SO2 since the kilns are by far the largest contributors to these pollutants. Since PM is calculated for all sources at NCC, we find it best to use the PM emission of 251.5 tons/years that was presented in the August 12th letter from NDEP. We would like to propose the new NOx emission rate of 2567.9 tons/year and the new SO2 emission rate of 332.1 tons/year. Let me know when you would like to discuss these revised emission rates.

Eric Dutcher
Environmental Manager
Nevada Cement Company
702-224-4335

Appendix B.5 - Tracy Generating Station, NV Energy

Appendix B.5.a	NDEP Reasonable Progress Determination for Tracy Generating Station
Appendix B.5.b	NV Energy Four-Factor Analysis for Tracy and Valmy Generating Stations
Appendix B.5.c	Response Letter 1
Appendix B.5.d	Response Letter 2
Appendix B.5.e	Response Letter 3
Appendix B.5.f	Response Letter 4
Appendix B.5.g	Response Letter 5.1
Appendix B.5.h	Response Letter 5.2
Appendix B.5.i	Response Letter 6
Appendix B.5.j	Response Letter 7
Appendix B.5.k	Response Letter 8

Appendix B.5.a - NDEP Reasonable Progress Determination for Tracy Generating Station

Tracy Generating Station Reasonable Progress Control Determination

Evaluation of existing and potential new control measures at NV Energy's Tracy Generating Station necessary to achieve reasonable progress for Nevada's second Regional Haze SIP.

Bureau of Air Quality Planning, Nevada Division of Environmental Protection

June 2022

1 Introduction

This document serves as the official reasonable progress determination for the Tracy Generating Station based on analyses submitted by the owner of the facility. The Long-Term Strategy of Nevada's Regional Haze SIP revision for the second implementation period covering years 2018 through 2028 will rely on the reasonable progress findings of this document. Potential new control measures are evaluated considering the four statutory factors to determine which measures are necessary to achieve reasonable progress. The four statutory factors include: cost of compliance, time necessary for compliance, energy and non-air environmental impacts, and remaining useful life of the source.

This reasonable progress determination references data and analyses provided by NV Energy (NVE) in several documents that can be found in Appendix B.5. Table 1-1 below outlines the documents submitted by NVE that supplement this determination document. In some cases, the Nevada Division of Environmental Protection (NDEP) adjusted information submitted by NVE to ensure the analyses relied on to make reasonable progress determinations agree with Regional Haze Rule regulatory language, Regional Haze Rule Guidance for the second implementation period, and EPA Control Cost Manual. Throughout the document, it can be assumed that referenced data and information rely on the following documents submitted by NVE, unless explicitly indicated that NDEP made adjustments.

Note that, the *NVE Analysis* includes the "Tracy Generating Station Four Factor Analysis" and "Valmy Generating Station Four Factor Analysis." The Tracy and Valmy Four Factor Analyses have separate chapters and appendices residing in the same *NVE Analysis* document. For the purpose of determining reasonable progress for the Tracy Generating Station, any references to the *NVE Analysis* pertains to the "Tracy Generating Station Four Factor Analysis" portion of the document.

Table 1-1: NVE Documents Relied upon for Reasonable Progress Determination

Full Document Title	Shortened Document Title (used in this document)	Date	Appendix Location
Regional Haze Reasonable Further Progress Four Factor Analysis	*NVE Analysis*	March 13, 2020	B.5.b
RE: Response to Request for Additional Information	*Response Letter 1*	July 8, 2020	B.5.c
RE: Response to a Second Follow-up Request for Additional Information	*Response Letter 2*	January 15, 2021	B.5.d
RE: Response to a Third Follow-up Request for Additional Information	*Response Letter 3*	April 16, 2021	B.5.e
RE: Response to a Fourth Follow-up Request for Additional Information	*Response Letter 4*	May 7, 2021	B.5.f
RE: Response to a Fifth Follow-up Request for Additional Information (Valmy specific)	*Response Letter 5.1*	August 27, 2021	B.5.g
RE: Response to a Fifth Follow-up Request for Additional Information (Tracy specific)	*Response Letter 5.2*	October 11, 2021	B.5.h
RE: Response to a Sixth Follow-up Request for Additional Information	*Response Letter 6*	April 29, 2022	B.5.i

RE: Response to a Seventh Follow-up Request for Additional Information	*Response Letter 7*	May 27, 2022	B.5.j
Class I Air Quality Operating Permit	Permit		A.5

2 Facility Characteristics

The NV Energy 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 one conventional, pipeline natural gas-fired steam boiler (Unit 3); two pipeline natural gas and distillate-fired combustion turbines (Units 5 and 6); one pipeline natural gas-fired combined cycle unit (Unit 7), and two pipeline natural gas-fired combined cycle units (Units 32 and 33). Table 2-1 lists the existing units at the Tracy Generating Station, along with identification numbers and unit descriptions. For the purpose of this reasonable progress determination, units are referred to by the associated NDEP Unit ID.

Table 2-1: Tracy Unit Descriptions

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)
Unit 7	Piñon Pine 4 (Unit 6)	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

3 Emissions Profile

Annual emissions reported by the facility were pulled from the National Emission Inventory (NEI), along with emissions data submitted in the *NVE Analysis* and *Response Letter(s)* that NDEP confirmed by cross checking the data using EPA's Emission Inventory System (EIS) Gateway. These emissions data were used for the source selection process, which Nevada determined using the Q/d method, and for development of baseline emissions to be relied on in the source's Four-Factor Analysis.

3.1 Q/d Emissions Profile

NDEP relied on the Q/d method for source selection by quantifying total facility-wide NO_x, SO_2, and PM_{10} emissions, represented as "Q", reported in the 2014 NEIv2. The Q value was then divided by the distance, in kilometers, between the facility and the nearest Class I area (CIA), represented as "d". The nearest CIA to the Tracy Generating Station is Desolation Wilderness at 82 kilometers away. NDEP elected to set a Q/d threshold of 5. As displayed in Table 3-1, using 2014 emissions, the Tracy

Generating Station yields a Q/d value of 8.33, effectively screening the facility into a four-factor analysis requirement for the second round of Regional Haze in Nevada.

Table 3-1: Tracy Generating Station Q/d Derivation

Facility Name	Nearest CIA	Total Q (tpy)	Distance to CIA (km)	Q/d
Tracy Generating Station	Desolation Wilderness	683	82	8.33

3.2 Baseline Emissions used for Screening Out Units

Units 5, 6, 32, and 33, were screened out from a four-factor analysis requirement when the *NVE Analysis* was submitted and is discussed further below in Section 4. In screening out these units, an emissions baseline from 2016-2018 was used, as 2018 annual emissions data was the most recent reporting year available when these units were screened out.

3.3 Baseline Emissions Profile for Four-Factor Analysis

In the *NVE Analysis*, an emissions baseline was derived from the average annual emissions reported from 2016 to 2018. When the *NVE Analysis* was submitted, 2018 was the latest year with reported annual emissions. Since then, reported annual emissions in 2019 and 2020 have become available for Tracy Generating Station, and have been incorporated into the baseline as a 5-year average from 2016 through 2020. The new baseline is presented in *Response Letter 3*.

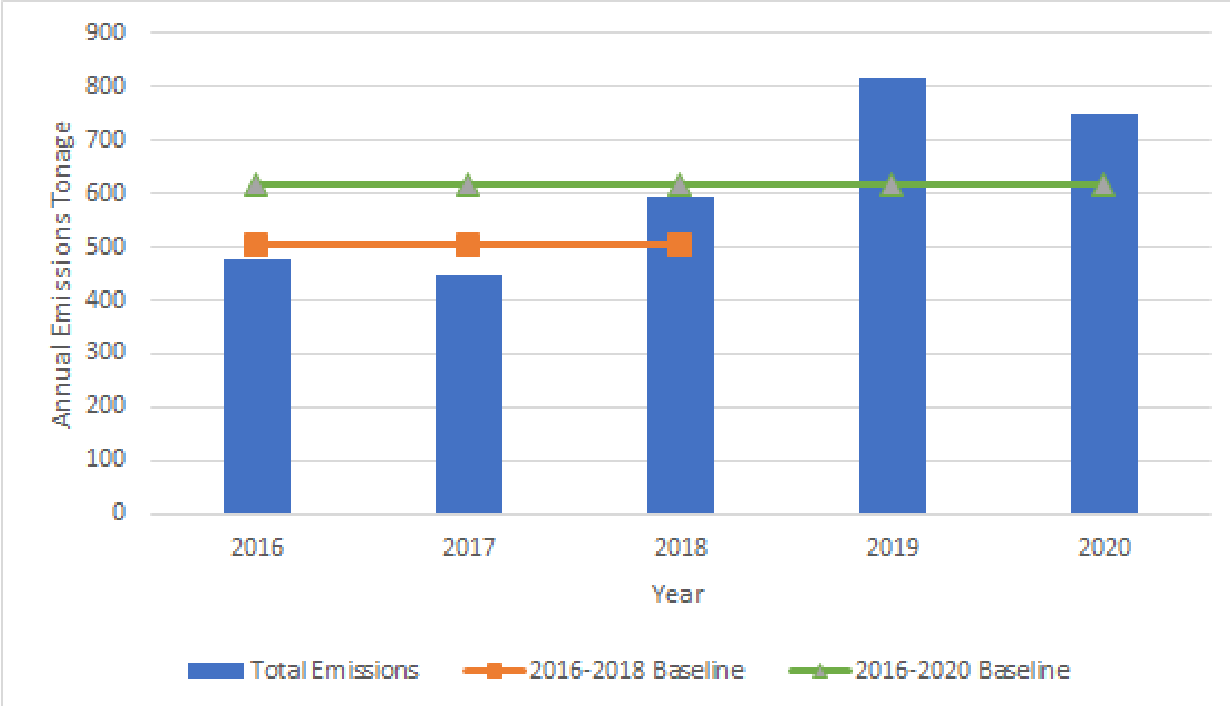
In *Response Letter 3*, the new 5-year baseline was applied to the cost analysis for Selective Catalytic Reduction (SCR) at Unit 7 (Piñon Pine) only. For consistency of this reasonable progress determination, NDEP has applied the new 2016-2020 5-year baseline to all controls considered. It is indicated below when NDEP has made adjustments to the baseline emissions used in NVE's cost analyses.

As shown in Table 3-2, an increase in facility-wide emissions were observed in 2019 and 2020 compared to the original baseline of 2016 through 2018, largely due to an increase in NO_x emissions. Figure 3-1 confirms that using a 2016 through 2020 baseline (green triangle) better accounts for this increase in emissions, as opposed to the original 2016 to 2018 baseline (orange square).

Table 3-2: Reported Annual Emissions

	Facility Emissions (tpy)				
Pollutant	**2016**	**2017**	**2018**	**2019**	**2020**
NO_x	351	328	510	659	616
SO_2	9	9	11	11	11
PM_{10}	115	112	73	144	121
Total	**475**	**449**	**594**	**814**	**748**

Figure 3-1: Original vs. New Baseline



4 Units Screened out from Four-Factor Analysis Requirement

Not all units at the Tracy Generating Station were required to be considered for potential new control measures. This was due to either low utilization, low emissions, or existing effective controls. Further explanation is provided below.

4.1 Units 5 and 6

NDEP is relying on the NVE's statement found on page 5 of the *NVE Analysis* to screen these units out from further consideration of potential new control measures based on low utilization and low emissions. Table 4-1 outlines annual average emissions for both units during the 2016 to 2018 period.

Table 4-1: Units 5 and 6 Emissions Profile

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

NDEP considers the continued use of Dry Low NO_x combustors, and associated NO_x limits, at both Unit 5 and 6 as necessary to achieve reasonable progress.

4.2 Units 32 and 33

NDEP is relying on the NVE's statement found on page 7 of the *NVE Analysis* to screen these units out from further consideration of potential new control measures based on existing effective controls and low emissions. Table 4-2 outlines annual average emissions for both units during the 2016 to 2018 period.

Table 4-2: Units 32 and 33 Emissions Profile

Unit ID	Average NO_x Emissions (tpy)	Average SO_2 Emissions (tpy)	Average PM_{10} Emissions (tpy)
Unit 32	38.5	4.0	24.3
Unit 33	37.5	4.0	23.8

NDEP considers the continued use of Dry Low NO_x combustors and Selective Catalytic Reduction (SCR), and associated NO_x limits, at both Unit 32 and 33 as necessary to achieve reasonable progress.

5 Unit 3 NO_x Control Determination

Since the Tracy Generating Station is natural gas fired and reported low SO_2 and PM_{10} historical emissions, only potential new control measures that reduce NO_x emissions are considered. NDEP does not consider additional SO_2 or PM_{10} control measures as technically feasible. There are currently no existing SO_2 or PM_{10} controls that could be considered necessary to achieve reasonable progress.

5.1 Existing Control Measures

To comply with BART during the first round of Regional Haze in Nevada, Unit 3 discontinued the occasional use of distillate fuel and was retrofitted with the best available Low-NOx Burners. NDEP considers the continued use of these control measures to reduce NO_x, SO_2, and PM_{10} emissions as necessary to achieve reasonable progress during the second implementation period of Nevada's Regional Haze SIP.

5.2 Potential New Control Measures

The implementation of Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) were considered as potential new control measures to further reduce NO_x emissions. A control efficiency of 90% was assumed for SCR and 25% for SNCR. An interest rate of 6.75% is used in calculating annualized capital costs, as this is the approved rate by the Public Utility Commission of Nevada (PUCN) and represents the "firm-specific nominal interest rate" that is preferred in the EPA Control Cost Manual. NDEP is relying on cost information submitted by NVE for determining whether controls are necessary to achieve reasonable progress, with minor edits made by NDEP to the achievable NO_x reductions by changing the emissions baseline from a 2016 through 2018 average to a 2016 through 2020 average. Table 5-1 summarizes the findings of the four-factor analysis conducted to consider potential new NO_x control measures at Unit 3.

Table 5-1: 4-Factor Summary of Technically Feasible NO_x Control Measures

Unit	Control	Cost of Compliance	Time Necessary for Compliance	Energy and Non-Air Quality Impacts	Remaining Useful Life
Unit 3	SCR	$11,186/ton	2-3 years following	1) Increased energy demand caused by backpressure	30 years

			SIP approval	2) Potential ammonia slip	
	SNCR	$13,561/ton		1) Potential ammonia slip	20 years

5.2.1 Baseline Emissions

For the purpose of considering additional NO_x control measures at Unit 3, NDEP is relying on an emissions baseline derived from the average NO_x emissions reported from 2016 through 2020. The use of the 5-year (2016-2020) average calculates baseline NO_x emissions at 138 tons per year for Unit 3, as opposed to the 3-year average (2016-2018) used by NVE that calculates 84 tons per year. Table 5-2 outlines the difference between NO_x emissions baselines used by NDEP and what was submitted in the *NVE Analysis* and *Response(s).*

Table 5-2: Change in NO_x Emissions Baseline 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				

5.2.2 Identification of Technically Feasible Controls

NDEP is relying on Section 5.2 found on page 3 of the *NVE Analysis* in determining technically feasible controls to consider in reducing NO_x emissions. For Unit 3, it is determined that SCR and SNCR are technically feasible.

5.2.3 Cost of Compliance

NDEP is relying on cost figures provided in Attachment A of *Response Letter 1* representing the implementation of SNCR and SCR on Unit 3. Table 5-3 outlines the major cost elements in implementing both control measures.

Table 5-3: Cost Figures for SCR and SCNR on Unit 3 provided by NVE

	SCR (30-year life)	**SNCR (20-year life)**
Estimated Capital Cost ($)	$15,564,000	$4,208,000
Annual Capital Recovery ($/yr)	$1,222,897	$389,521
Annual Operating Cost ($/yr)	$164,143	$85,120
Total Annual Costs ($/yr)	$1,387,040	$474,641
NOx Emission Rate w/ Controls (tpy)	8.4	62.9
NOx Emission Reduction (tpy)	75.5	21.0
Control Cost Effectiveness ($/ton)	**$18,371/ton**	**$22,602/ton**

As stated above, NDEP is relying on a 2016-2020 baseline, instead of 2016-2018. This alters the final control cost effectiveness for both controls. New control cost effectiveness figures for both controls using the 2016-2020 baseline is shown in Table 5-4. The use of the new baseline changes the cost effectiveness of implementing SCR on Unit 3 from $18,371 per ton to $11,186 per ton. Cost effectiveness of implementing SNCR on Unit changes from $22,602 per ton to $13,561 per ton. Even with the new NO_x emissions baseline, the cost effectiveness for both controls are above the threshold set by NDEP. NDEP does not consider SCR or SNCR as cost-effective, or necessary to achieve reasonable progress during the second round, for Unit 3.

Table 5-4: Change in Cost-Effectiveness for SCR and SNCR with new NO_x Emissions Baseline

Baseline		**2016-2018**	**2016-2020**
Average Annual Emissions		**84 tpy**	**138 tpy**
SCR	Control Efficiency	90%	90%
	Reduced Tons of NO_x	76	124
	Annual Cost	$1,387,040	$1,387,040
	Cost-Effectiveness	**$18,371/ton**	**$11,186/ton**
SNCR	Control Efficiency	25%	25%
	Reduced Tons of NO_x	21	35
	Annual Cost	$474,641	$474,641
	Cost-Effectiveness	**$22,602/ton**	**$13,561/ton**

5.2.4 Time Necessary for Compliance

NDEP is relying on NVE's statement on page 8 of the *NVE Analysis* that concludes that the time necessary for compliance would be two to three years after SIP approval. This timeframe includes design, permitting, procurement, installation, startup, and schedules that support regional electrical needs during the unit's outage.

5.2.5 Energy and Non-Air Quality Environmental Impacts

NDEP is relying on NVE's assessment of energy and non-air quality environmental impacts found on page 9 of the *NVE Analysis*. Both SNCR and SCR have the potential to produce "ammonia slip."

Installation of SCR in the exhaust flow path of the boiler causes a backpressure which must be offset by increased electrical demand. This increased energy use is reflected in the economic analysis as one of the operating costs for SCR. An annual electricity cost of $48,551 in 2019 dollars is estimated in Appendix B of the "Tracy Generating Station Four Factor Analysis" within the *NVE Analysis*.

5.2.6 Remaining Useful Life of the Source

There is currently no federally enforceable closure date of Unit 3 that would restrict the remaining useful life of the unit when considering annualized capital costs. Because of this, NDEP is relying on the recommended life of SNCR and SCR listed in the EPA Control Cost Manual of 20 years and 30 years, respectively.

5.2.7 Determination for Potential New Measures to Control NO_x Emissions

For existing measures, NDEP considers the continued use of BART controls from the first round (natural gas only as fuel along with the use of Low NO_x Burners) to reduce emissions as necessary to achieve reasonable progress. Since these BART controls are already part of Nevada's first Regional Haze SIP, these controls are not added to Nevada's Long Term Strategy for the second implementation period.

For potential new measures, NDEP does not consider SNCR or SCR as cost effective, or necessary to achieve reasonable progress.

6 Unit 7 NO_x Control Determination

Since the Tracy Generating Station is natural gas fired and reported low SO_2 and PM_{10} historical emissions, only potential new control measures that reduce NO_x emissions are considered. NDEP does not consider additional SO_2 or PM_{10} control measures as technically feasible. There are currently no existing SO_2 or PM_{10} controls that could be considered necessary to achieve reasonable progress.

Note that NVE has agreed to commit to a federally enforceable closure date of December 31, 2031 for Unit 7. This closure date decreases the remaining useful life and inflates the cost effectiveness figures for potential new controls at Unit 7. The closure date will be incorporated into the facility's air quality operating permit to be made federally enforceable and permanent. NDEP considers this closure date as necessary to achieve reasonable progress during the second round of Nevada's Regional Haze SIP.

6.1 Existing Control Measures

Currently, the turbine uses steam injection to partially quench the heat of combustion to control NO_x emissions to approximately 41 ppm at 15% O2 (2016-2018 average). NDEP considers the continued use of this control measure to control NO_x emissions as necessary to achieve reasonable progress.

6.2 Potential New Control Measures

The implementation of Selective Catalytic Reduction (SCR) and a Dry Low NO_x combustor system were considered as potential new control measures to further reduce NO_x emissions at Unit 7. A control efficiency of 90% was assumed for SCR and 60% for the Dry Low NO_x combustor. An interest rate of 6.75% is used in calculating annualized capital costs, as this is the approved rate by the Public Utility Commission of Nevada (PUCN) and represents the "firm-specific nominal interest rate" that is preferred in the EPA Control Cost Manual. NDEP is relying on cost information submitted by NVE for determining whether controls are necessary to achieve reasonable progress, with minor edits made by NDEP to the achievable NO_x reductions by changing the emissions baseline from a 2016 through 2018 average to a 2016 through 2020 average. Table 6-1 summarizes the findings of the four-factor analysis conducted to consider potential new NO_x control measures at Unit 7.

Table 6-1: 4-Factor Summary of Technically Feasible NOx Control Measures

Unit	Control	Cost of Compliance	Time Necessary for Compliance	Energy and Non-Air Quality Impacts	Remaining Useful Life
Unit 7	SCR	$10,064/ton	47 months	Potential ammonia slip and increased pressure drop.	6 years
	Dry Low NOx Combustor	$17,355/ton	2 years	Negative impact on plant water balance	9 years

				and decreased electricity generation of the turbine	

6.2.1 Baseline Emissions

For the purpose of considering additional NO_x control measures at Unit 7, NDEP is relying on an emissions baseline derived from the average NO_x emissions reported from 2016 through 2020. NVE submitted cost of compliance figures considering the implementation of a Dry Low NOx combustor based on a NO_x emissions baseline derived from a 2016 through 2018 period and submitted cost of compliance figures considering the implementation of SCR based on a NO_x emissions baseline derived from a 2016 through 2020 period. For consistency, NDEP has modified the cost calculations for a Dry Low NO_x Burner to reflect a 2016 through 2020 baseline. The use of the 5-year (2016-2020) average calculates baseline NO_x emissions at 250 tons per year for Unit 7, as opposed to the 3-year average (2016-2018) used by NVE that calculates 213 tons per year. Table 6-2 outlines the difference between NO_x emissions baselines used by NDEP and what was submitted in the *NVE Analysis* and *Response(s).*

Table 6-2: Change in NO_x Emissions Baseline for Unit 7

	Unit 7 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				

6.2.2 Identification of Technically Feasible Controls

NDEP is relying on Section 5.2 found on page 3 of the *NVE Analysis* in determining technically feasible controls to consider in reducing NOx emissions. For Unit 7, it is determined that SCR and Dry Low NO_x combustor systems are technically feasible.

6.2.3 Cost of Compliance

NDEP is relying on cost information submitted in *Response Letter 5.2* in evaluating the cost of implementing SCR on Unit 7. NDEP is partially relying on cost information submitted in *Response Letter 6* in evaluating the cost of implementing a Dry Low NO_x Combustor system on Unit 7. For these calculations, NDEP has only modified the annual achievable NO_x reductions through use of this control by changing the assumed NO_x emissions baseline from a 2016 through 2018 average to a 2016 through 2020 average. This slightly increased the NO_x emissions baseline for Unit 7, which increased the achievable reductions, and decreased the final cost-effectiveness value. Table 6-3 outlines the major cost elements in implementing both control measures.

Table 6-3: Cost Figures for SCR and Dry Low NO_x Combustor on Unit 7 provided by NVE

	SCR	**Dry Low NO_x Combustor**
Estimated Capital Cost ($)	$8,836,600	$13,464,516
Annual Capital Recovery ($/yr)	$1,839,598	$2,044,697

Annual Operating Cost ($/yr)	$419,811	$680,000
Total Annual Costs ($/yr)	$2,259,408	$2,724,697
NOx Emission Rate w/ Controls (tpy)	25 tpy	93 tpy
NOx Emission Reduction (tpy)	225 tpy	157 tpy
Control Cost Effectiveness ($/ton)	**$10,064/ton**	***$17,355/ton**

*Different from $/ton submitted by NVE ($20,183/ton). This is due to application of 2016-2020 baseline (250 tpy) compared to the 2016-2018 baseline (213 tpy) used by NVE in calculations. This increases the NOx emission reduction from 135 tpy to 157 tpy.

6.2.4 Time Necessary for Compliance

As stated in *Response Letter 5.2* 47 months would be needed to fully implement an SCR system on Unit 7. As stated in the *NVE Analysis*, a Dry Low NO_x Combustor conversion could be implemented in two years, however, the remaining useful life conservatively assumes that it could be implemented within six months.

6.2.5 Energy and Non-Air Quality Environmental Impacts

NDEP is relying on NVE's assessment of energy and non-air quality environmental impacts found on page 9 of the *NVE Analysis*. SCR has the potential to produce "ammonia slip."

Installation of SCR in the exhaust flow path of the boiler causes a backpressure which must be offset by increased electrical demand. This increased energy use is reflected in the economic analysis as one of the operating costs for SCR. An annual power cost due to the SCR pressure drop is estimated at $154,828 in Attachment C of *Response Letter 2*.

For the installation of a Dry Low NO_x Combustor, NVE states in the *NVE Analysis* that this control would have a negative impact on the plant's water balance and result in a wastewater stream that would require treatment or disposal. A DLN conversion would also decrease the electrical generation of the turbine because of the decreased mass flow. This would add an annual cost of $870,000 in energy purchases.

6.2.6 Remaining Useful Life of the Source

NDEP is relying on NVE's response in *Response Letter 5.2* that estimates a service life of at most only 6 years before permanent shutdown of the unit for SCR implementation.

NDEP is relying on NVE's response in *Response Letter 6* that assumes a 9-year life for a Dry Low NO_x Combustor on Unit 7 given that the control go online by the end of 2022 and the unit permanently ceases operation at the end of 2031.

6.2.7 Determination for Potential New Measures to Control NO_x Emissions

For existing measures, NDEP considers the continued use of steam injection to control NO_x emissions as necessary to achieve reasonable progress at Unit 7.

For potential new measures, NDEP does not consider Dry Low NO_x Combustor conversion or SCR as cost effective, or necessary to achieve reasonable progress.

7 Control Measures Necessary to Make Reasonable Progress

As stated above, NDEP is relying on the continued use of existing NO_x controls at Units 5, 6, 32, and 33 to make reasonable progress. For Unit 7, NDEP is relying on a federally enforceable closure date of December 31, 2031, along with the continued use of existing NO_x controls until Unit 7 is shut down and permanently ceases operation, as necessary to make reasonable progress.

NDEP is submitting the following controls, emission limits, and associated requirements, for approval into the SIP as measures necessary to make reasonable progress during second implementation period of Nevada's Regional Haze SIP. These emission limits and associated requirements, listed in the source's air quality operating permit, are incorporated into the SIP by reference. The Tracy Generating Station's permit, Permit No. AP4911-0194.04, can be found in Appendix A.5 of Nevada's second Regional Haze SIP.

7.1 Unit 3 BART Limits and Associated Requirements

For Unit 3 (System 03A – Tracy Unit #3 Steam Boiler) [S2.003] Pipeline Quality Natural Gas-Fired.

7.1.1 Emission Limits found in Section IV.A.5 of Permit No. AP4911-0194.04

c. Control Measures Constituting Best Available Retrofit Technology (BART); Limitations on Emissions (NAC 445B.22096) *Federally Enforceable SIP Requirement*

Permittee must install, operate and maintain on **S2.003** the following control measures which constitute BART and must not emit or cause to be emitted NO_x, SO_2, or PM_{10}, in excess of the following limits on or before January 1, 2015, or not later than 5 years after approval of Nevada's state implementation plan for regional haze by the United State Environmental Protection Agency, Region 9, whichever occurs first:

(1) Control measures: low NO_x burners with flue gas recirculation and combust only pipeline quality natural gas and/or fuel oil.

(2) The discharge of SO_2 to the atmosphere will not exceed 0.05 lb/MMBtu based on a 24-hour average.

(3) The discharge of PM_{10} to the atmosphere will not exceed 0.03 lb/MMBtu based on a 3-hour average.

(4) The discharge of NO_x to the atmosphere will not exceed 0.19 lb/MMBtu based on a 12-month rolling average.

7.1.2 Monitoring, Recordkeeping, and Reporting Requirements

NDEP is relying on the monitoring, recordkeeping, and reporting requirements listed in Section V.A and Section IV.A.6 of Permit No. AP4911-0194.04.

7.1.3 Compliance Deadline

NDEP is not proposing a compliance deadline as these limits and associated requirements reflect the use of controls that were already implemented at Unit 3 prior to the second implementation period of the Regional Haze Rule.

7.2 Unit 5 Limits and Associated Requirements

For Unit 5 (System 05A – Clark Mountain Combustion Turbine #3) [S2.006] Pipeline Quality Natural Gas-Fired.

7.2.1 Emission Limits found in Section IV.B.3 of Permit No. AP4911-0194.04:

1. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

<u>Air Pollution Control Equipment</u>

Emissions from **S2.006** shall be controlled by a dry low NO_x burner while combusting natural gas. Emissions from **S2.006** shall be controlled by water injection shall be used while firing No. 2 distillate fuel oil under "Emergency" conditions defined in O.3.d.

2. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

Emission Limits

a. On and after the date of startup of **S2.006**, ***the Permittee*** will not discharge or cause the discharge into the atmosphere from the exhaust stack of **S2.006**, the following pollutants in excess of the following specified limits:

(4) NAC 445B.305 *Part 70 Program* - The discharge of **NO_x** (nitrogen oxide) to the atmosphere will not exceed:

(i) 9 parts per million by volume (ppmv) at 15 percent oxygen and on a dry basis, based on a 24-hour rolling average period;

(ii) 42.0 pounds per hour, based on a 720-hour rolling average period;

(iii) 122.64 tons per year, based on a 12-month rolling average period.

7.2.2 Monitoring, Recordkeeping, and Reporting Requirements

NDEP is relying on the monitoring, recordkeeping, and reporting requirements listed in Section V.A and Section IV.B.5 of Permit No. AP4911-0194.04.

7.2.3 Compliance Deadline

NDEP is not proposing a compliance deadline as these limits and associated requirements reflect the use of controls that were already implemented at Unit 5 prior to the second implementation period of the Regional Haze Rule.

7.3 Unit 6 Limits and Associated Requirements

For Unit 6 (System 06A – Clark Mountain Combustion Turbine #4) [S2.007] Pipeline Quality Natural Gas-Fired.

7.3.1 Emission Limits found in Section IV.D.3 of Permit No. AP4911-0194.04:

1. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

Air Pollution Control Equipment

Emissions from **S2.007** shall be controlled by a dry low NOx burner while combusting natural gas. Emissions from **S2.007** shall be controlled by water injection shall be used while firing No. 2 distillate fuel oil under "Emergency" conditions defined in S.3.d.

2. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

Emission Limits

a. On and after the date of startup of **S2.007**, ***the Permittee*** will not discharge or cause the discharge into the atmosphere from the exhaust stack of **S2.007**, the following pollutants in excess of the following specified limits:

(4) NAC 445B.305 *Part 70 Program* - The discharge of **NO_x** (nitrogen oxide) to the atmosphere will not exceed:

(i) 9 parts per million by volume (ppmv) at 15 percent oxygen and on a dry basis, based on a 24-hour rolling average period;

(ii) 42.0 pounds per hour, based on a 720-hour rolling average period;

(iii) 122.64 tons per year, based on a 12-month rolling average period.

7.3.2 Monitoring, Recordkeeping, and Reporting Requirements

NDEP is relying on the monitoring, recordkeeping, and reporting requirements listed in Section V.A and Section IV.D.5 of Permit No. AP4911-0194.04.

7.3.3 Compliance Deadline

NDEP is not proposing a compliance deadline as these limits and associated requirements reflect the use of controls that were already implemented at Unit 6 prior to the second implementation period of the Regional Haze Rule.

7.4 Unit 7 Limits and Associated Requirements

For Unit 7 (System 07C – Tracy Unit #4 Piñon Pine Combustion Turbine) [S2.009] [S2.009.1] Pipeline Quality Natural Gas-Fired. The continuous use of existing NO_x control measures is necessary to make reasonable progress until the Unit 7 is shut down and permanently ceases operation.

7.4.1 Emission Limits found in Section IV.F.3 of Permit No. AP4911-0194.04

1. NAC 445B.3405 *Part 70 Program*

   Air Pollution Control Equipment

   Control system for Combustion Turbine Unit #4 **(S2.009)** shall consist of steam injection for control of NOx.

   Control system for Combustion Turbine Unit #4 Duct Burner **(S2.009.1)** shall consist of duct burner design for NOx and CO.

2. NAC 445B.3405 *Part 70 Program*

   Emission Limits

   a. On and after the date of startup of **S2.009** and **S2.009.1**, ***the Permittee*** will 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:

   (4) NAC 445B.305 *Part 70 Program* - The discharge of **NOx** (nitrogen oxide) to the atmosphere will not exceed 141.0 pounds per hour, nor more than 533.10 tons per year (based on a 12-month rolling period).

7.4.2 Monitoring, Recordkeeping, and Reporting Requirements

NDEP is relying on the monitoring, recordkeeping, and reporting requirements listed in Section V.A and Section IV.F.5 of Permit No. AP4911-0194.04.

7.4.3 Compliance Deadline

NDEP is incorporating the following permit condition by reference, found in Section VIII.A of Permit No. AP4911-0194.04, for approval in the SIP to establish a closure date of December 31, 2031, at Unit 7 to make reasonable progress.

Section VIII. Schedules of Compliance

A. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

   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.

7.5 Unit 32 Limits and Associated Requirements

For Unit 32 (System 32 – Combined Cycle Combustion Turbine Circuit No. 8) [S2.064] [S2.065] Pipeline Quality Natural Gas-Fired, 254 MW Output Nominal.

7.5.1 Emission Limits found in Section IV.L.3 of Permit No. AP4911-0194.04

1. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

   Air Pollution Control Equipment

   a. Emissions from **System 32** shall be ducted to the following emissions control system with 100% capture and a maximum volume flow rate of 960,000 dry standard cubic feet per minute (DSCFM):

   (1) Selective Catalyst Reduction (SCR) system for the control of NO_x emissions. The SCR shall utilize ammonia injection into the SCR at a volume specified by the manufacturer.

2. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

   Emission Limits

   a. On and after the date of startup of **S2.064 and S2.065**, ***the Permittee*** will not discharge or cause the discharge into the atmosphere from the exhaust stack of **System 32 (S2.064 and S2.065 combined)**, the following pollutants in excess of the following specified limits:

(7) NAC 445B.305 *BACT Emission Limit* – The discharge of **NO_x** to the atmosphere will not exceed **2.0** parts per million by volume (ppmv) at 15 percent oxygen and on a dry basis, based on a 3-hour rolling period.

7.5.2 Monitoring, Recordkeeping, and Reporting Requirements

NDEP is relying on the monitoring, recordkeeping, and reporting requirements listed in Section V.A and Section IV.L.4 of Permit No. AP4911-0194.04.

7.5.3 Compliance Deadline

NDEP is not proposing a compliance deadline as these limits and associated requirements reflect the use of controls that were already implemented at Unit 32 prior to the second implementation period of the Regional Haze Rule.

7.6 Unit 33 Limits and Associated Requirements

For Unit 33 (System 33 – Combined Cycle Combustion Turbine Circuit No. 9) [S2.066] [S2.067] Pipeline Natural Gas-Fired, 254 MW Output Nominal.

7.6.1 Emission Limits found in Section IV.M.3 of Permit No. AP4911-0194.04

1. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

   Air Pollution Control Equipment

   a. Emissions from **System 33** shall be ducted to the following emissions control system with 100% capture and a maximum volume flow rate of 960,000 dry standard cubic feet per minute (DSCFM):

   (1) Selective Catalyst Reduction (SCR) system for the control of NO_x emissions. The SCR shall utilize ammonia injection into the SCR at a volume specified by the manufacturer.

2. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

   Emission Limits

   a. On and after the date of startup of **S2.066 and S2.067**, ***the Permittee*** will not discharge or cause the discharge into the atmosphere from the exhaust stack of **System 33 (S2.066 and S2.067 combined)**, the following pollutants in excess of the following specified limits:

   (7) NAC 445B.305 *BACT Emission Limit* – The discharge of **NO_x** to the atmosphere will not exceed **2.0** parts per million by volume (ppmv) at 15 percent oxygen and on a dry basis, based on a 3-hour rolling period.

7.6.2 Monitoring, Recordkeeping, and Reporting Requirements

NDEP is relying on the monitoring, recordkeeping, and reporting requirements listed in Section V.A and Section IV.M.4 of Permit No. AP4911-0194.04.

7.6.3 Compliance Deadline

NDEP is not proposing a compliance deadline as these limits and associated requirements reflect the use of controls that were already implemented at Unit 33 prior to the second implementation period of the Regional Haze Rule.

Appendix B.5.b - NV Energy Four-Factor Analysis for Tracy and Valmy Generating Stations

NV Energy

March 13, 2020

Sig Jaunarajs
Nevada Department of Environmental Protection
901 S. Stewart Street
Suite 4001
Reno, NV 89701

Re: Regional Haze 4 Factor Analysis
NV Energy Tracy (FIN 0029) and Valmy (FIN A0375) Generating Stations

Mr. Jaunarajs:

Nevada Power Company d/b/a NV Energy (NVE) hereby provides a final summary of the identified emission controls and expected emissions reductions at both the Tracy and North Valmy Generating Stations for the purposes of the current Regional Haze planning period. These analyses are being provided per Nevada Department of Environmental Protection's (NDEP's) request for planning purposes. A draft four-factor assessment dated January 3, 2020 was previously submitted to NDEP, whereas this final assessment contains further details and supporting documentation of NVE's analysis.

NVE appreciates the opportunity to work with NDEP in this endeavor. Please feel free to contact Sean Spitzer at (702) 402-5132 should you have any questions.

Sincerely,

Starla Lacy
Vice President, Environmental Services, Safety, and Land Management
NV Energy

Imagine it.
Delivered.

Regional Haze Reasonable Further Progress Four Factor Analysis

NV Energy Tracy Generating Station

AECOM Project Number: 60619218

Prepared for:

NV Energy
6226 W Sahara Ave
Las Vegas, NV 89146

Prepared by:

AECOM Technical Services, Inc.
1601 Prospect Parkway
Suite 120
Fort Collins, CO 80525

March 13, 2020

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 Tracy Generating Station as a source where further analysis is warranted 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 rules, the analysis needs to first identify all feasible control technologies 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

Additionally, consideration of a fifth factor, evaluation of the visibility benefits of each option, is not required, but states may consider visibility in addition to the four statutory factors when making their reasonable progress determinations.

Accordingly, this report presents NV Energy's evaluation of the emissions rates and potential emission controls for the Tracy Generating Station. This report provides a description of the facility (Section 2), a summary of the actions taken during First Decadal Review period of the Regional Haze Rule (Section 3), a summary of each unit's baseline emissions (Section 4), identification of potentially feasible control options (Section 5), and an assessment of each of the four statutory factors for feasible control options (Section 6). Additionally, NVE has included Section 7 and Appendix A providing additional considerations regarding the prospective visibility impacts to Class I areas of potential controls for NDEPs consideration. And finally, Section 8 presents a summary of this report's findings.

2. Facility Description

The NV Energy 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 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); one pipeline natural gas-fired combined cycle unit (Tracy Piñon Pine #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 shut down several years ago.

3. First Regional Haze Planning Period Reasonable Progress Determination

During the First Decadal Review period of the Regional Haze Rule (i.e., 40 CFR 51 §§308 and 309), Units 1, 2, and 3 were subject to Best Available Retrofit Technology (BART) review. They were the only units that had been in existence during the rule-specified BART applicability window (between August 7, 1962 and August 7, 1977). The BART review lead to a requirement to add controls to all three of these units. However, Units 1 and 2 have since been permanently retired. Unit 3 implemented low-NOx burners and eliminated oil firing as BART and remains in operation. Further information about these three units is provided in Section 5.

4. Baseline Emissions Summary

Table 1 below summarizes the recent past "Baseline" emissions (2016-2018 Annual Average) for the three visibility-impairing pollutants from the Tracy Generating Station units. As there is currently no substantial basis to forecast a significant change in operation in 2028, these recent past emissions are a reasonable basis to estimate near term future emissions if no additional controls are implemented.

Table 1 – Tracy Power Station – Average 2016-2018 Emissions from Combustion Sources

Unit ID	NVE 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 1	1	Steam Boiler (NG or Distillate) 55 MW	N/A	Permanently Retired		
Unit 2	2	Steam Boiler (NG or Distillate) 83 MW	N/A	Permanently Retired		
Unit 3	3	Steam Boiler (NG) 113 MW	LNB	83.9	0.4	1.6
Unit 4	Clark Mountain 3	GE EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)	Dry Low NOx combustors w/NG (water injection if Distillate)	12.0	0.3	1.0
Unit 5	Clark Mountain 4	GE 7EA Combustion Turbine, Simple Cycle NG-fired 83.5 MW (Distillate for emergency only)	Dry Low NOx combustors w/NG (water injection if Distillate)	10.6	0.2	0.8

Unit ID	NVE 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	213.1	0.9	7.4
Unit 8	Unit 8	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 mmbtu/hr duct burners	Low NOx Combustors, SCR, & Ox. catalyst	38.5	4.0	24.3
Unit 9	Unit 9	GE 7F NG Combined Cycle Combustion Turbine 254 MW with 660 mmbtu/hr duct burners	Low NOx Combustors, SCR, & Ox. catalyst	37.5	4.0	23.8

5. Identification of Potentially Feasible Emission Controls

To begin a Four Factor analysis, it is first necessary to identify emissions control options potentially feasible for each source. This section presents an evaluation of the technical feasibility of potential control options for each emission source at the Tracy Generating Station. As is discussed below, several of the sources and emissions at this facility are either too small or are already so well controlled that there are no further control options that need to be considered. For the sources with potential further control opportunities, Section 6 continues their analysis by evaluating each option relative to the Regional Haze Rule statutory four factors (cost, timing, other Impacts, and remaining useful life)

5.1 Sulfur Dioxide and Particulate Matter Controls

All the generating units at the Tracy Generating Station currently burn only pipeline natural gas as their fuel. Tracy Unit 3 had historically been capable of burning distillate fuel. However, to comply with BART as part of the first decadal regional haze review, this unit discontinued its use of distillate fuel. Additionally, Units 4 and 5 (Clark Mountain #3 and #4) are allowed to fire distillate fuel in emergencies, although that hasn't occurred in recent history. Consequently, the use of pipeline natural gas fuel to all the units minimizes the emissions of SO_2 and particulate matter (PM_{10}) emissions. No further emissions controls for these pollutants are technically feasible.

5.2 Nitrogen Oxides Control Options

Unit 1 and 2 – Steam Boilers (Retired)

Tracy Units 1 and 2 were Riley Steam boilers, 55 and 85 MW nominal output respectively, capable of firing either pipeline natural gas or distillate oil. Both were shut down several years ago and permanently retired in 2014. During the first round of regional haze reviews, these units were still operating and were subject to Best Available Retrofit Technology (BART) review. Their combined NOx emissions, pre-BART, were approximately 440 tons/yr (2002-2007 period average). BART was determined to be the implementation of a LNB/FGR combustion system upgrade forecast to achieve approximately 30% reduction to NOx. Instead, NVE went further and retired these units on December 31, 2014 and subsequently removed them from the Title V operating permit. Their shutdown provides a "beyond BART" emissions reduction for this current reasonable progress review of 307 tons/yr (zero emissions compared to 307 tons/yr NOx if they continued to operate and achieved the BART-specified level of performance).

Since these units no longer operate, no further control analysis is needed.

Unit 3 – 113 MW Steam Boiler

Tracy Unit #3 is a boiler rated at 1,150 MMBtu/hr or 113 MW nominal capacity firing only pipeline natural gas. It was constructed in 1974 and was subject to BART during the first phase of regional haze reviews. To comply with BART, this unit discontinued the occasional use of distillate fuel and was retrofitted with the best available Low-NOx Burners which significantly lowered its NOx emissions rate.

Although NOx is already controlled to BART levels, further controls are technically feasible. The two additional NOx controls that are feasible for pipeline natural gas-fired boilers are Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction.

<u>Selective Non-Catalytic Reduction</u>

SNCR has been applied to control NOx from a wide range of combustion sources burning a variety of fuels. With SNCR, 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 in the furnace 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 promote the reaction between NOx and the reducing agent.

SNCR removal efficiencies typically range between 10-40% depending on a number of unit-specific design/operating parameters. The Tracy 3 boiler is of the tower type design with horizontal superheaters which results in very high furnace exit gas temperatures that are not optimal for SNCR NOx control. Additionally, there is a relatively small reducing residence time within the boiler. The combination of these factors would significantly limit the effectiveness of SNCR. For the purposes of this analysis, a NOx reduction of 25% has been conservatively assumed, but actual performance may be significantly lower.

SNCR for the Tracy Unit 3 Boiler is a technically feasible NOx control option and is carried forward in the Four Factor analysis in Section 6.

Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) can be used on many types of fossil fuel fired combustion devices including pipeline natural gas-fired boilers. SCR utilizes the same chemical conversion process as occurs with SNCR whereby NOx is chemically reduced to nitrogen and water with ammonia or urea used as the reducing agent. However, with SCR a catalyst is used to increase the NOx control efficiency and to allow operation at a lower operating temperature than with SNCR. The preferred flue gas temperature range for conventional SCR catalyst is 650 °F to 725 °F.

SCR typically provides between 70% and 90% control depending on many unit specific and design factors. For the purposes of this analysis, SCR is assumed to be capable of providing 90% control of NOx for Tracy Unit 3.

SCR for the Tracy Unit 3 boiler is a feasible control option and is carried forward in the Four Factor analysis in Section 6.

Units 4 and 5 – GE 7EA Simple Cycle NG Fired Turbines

Tracy Units 4 and 5 (Clark Mountain Units 3 and 4) are both GE 7EA NG-fired turbines rated at 1011.2 MMBtu/hr. They were constructed in 1994 and operate in simple cycle mode in peaking services. They are capable of firing diesel fuel but are only allowed to do so in emergency situations. They have not been fired with diesel in recent history. NOx emissions are controlled with dry low NOx (DLN burners) and achieve approximately 9 ppm NOx (at 15% O_2) firing pipeline natural gas.

In peaking service, the annual capacity utilization of these turbines is typically very low as evidenced by the 2016 to 2018 average capacity utilization of each turbine of less than 10%. The low usage of these turbines combined with their already good emissions controls results in relatively small emissions as shown in previous Table 1. It is not expected that any further controls would be reasonably cost-effective. Accordingly, NDEP indicated to NVE that these units did not need to be reviewed for further "reasonable progress". Further, the current turbine operation's low emissions are not expected to impact visibility in nearby Class I areas. Based on the distance of the Tracy Power Station from the nearest Class I area (Desolation Wilderness) of 81 km, the Q/D ratio of each of these turbine emissions is less than 0.2 (where Q = tons/yr of NOx + SO_2 + PM10, and D = 81 km).

For the above reasons, no further control analysis for these units is needed.

Unit 6 – Piñon Pine # 4 GE 6FA NG Combined Cycle Turbine.

Tracy Unit #6 (Piñon Pine #4) is a GE 6FA natural gas-fired turbine operating with a heat recovery steam generator in combined cycle mode. It is rated at 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 (2016-2018 average).

Additional NOx controls that are technically feasible would be a combustor conversion to the latest GE dry low NOx (DLN) combustor (replacing the current steam injection) or installation of selective catalytic reduction (SCR). (Note: Selective non-catalytic reduction (SNCR) is not technically feasible for a combustion turbine because the exhaust temperatures are too low.)

<u>Dry Low NOx Combustor</u>

For this type of pipeline natural gas-fired turbines, GE offers a lean premixed Dry Low NOx combustor system capable of better performance than steam injection. 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 this 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>

Selective Catalytic Reduction (SCR) can be used as an add-on control technology for a combustion turbine. As discussed previously, SCR uses a catalyst and ammonia reagent injection to convert NOx to N_2 and H_2O. 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 is at this temperature in the middle of the heat recovery steam generator.

For this turbine, the existing HRSG appears to have room to accommodate SCR catalyst in the right temperature range after the high pressure "superheaters" steam coils and before the "economizer" and various low-pressure steam coils. 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 controls and are evaluated further in Section 6 relative to the Regional Haze Rule's four factors.

Units 8 & 9 – Two GE 7F NG-Fired Combined Cycle Turbines with SCR
Units 8 and 9 are General Electric frame 7F combustion turbines each rated at 1,722 MMBtu/hr with duct burners rated at 660 MMBtu/hr. The units are already equipped with DLN combustors and Selective Catalytic Reduction (SCR) to control NOx emissions, as well as an Oxidation Catalyst to control CO and VOC emissions. The units were constructed in 2008 and currently achieve approximately 2 ppm NOx (at 15% O_2).

These turbine's current use of SCR represents the highest level of NOx control for this type of source. Therefore, there are no additional NOx control options to consider for improved control.

6. Four Factor Analysis

The previous section presented an analysis of the control technologies that are potential feasible to lower the emissions of NOx, PM or SO_2 for each emission unit at the Tracy Generating Station. Only units 3 and 6 were identified as having technically feasible control options for possible further improvements to regional haze. The identified control options for further evaluation for these two units are as follows:

Unit # 3 (Steam Boiler with DLN burners) Potential Control Options:

- Selective Non-Catalytic Combustion (SNCR); or
- Selective Catalytic Reduction (SCR).

Unit #6 (Piñon Pine #4 Combined Cycle Turbine with Steam Injection) Potential Control Options:
- Retrofit with GE DLN 2.6 Combustor; or
- 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

6.1 Tracy Unit 3 (Steam Boiler)

Cost of Implementing Emissions Controls

Selective Non-Catalytic Combustion (SNCR) and Selective Catalytic Reduction (SCR) are both technically feasible controls for reducing NOx on this source. The costs of implementing SNCR and SCR for Tracy Unit #3 were estimated using US EPA's cost spreadsheets[1]. These EPA spreadsheets use the methodologies in the US EPA Control Cost Manual[2]. Both the SNCR and SCR spreadsheets were updated by US EPA in 2019. A retrofit factor of 1.0 was used for both controls based on the assumption that retrofit of this unit would likely be relatively straight forward. For annualization of the capital cost, the remaining useful life/plant life was set as 20 years beyond the SNCR or SCR installation date.

The following Table 2 shows the estimated capital and annual costs for these control methods.

Table 2 – Tracy Unit #3 NOx Control Option Cost-Effectiveness

Selective Non-Catalytic Reduction	
Estimated Capital Cost	$4.21 million
Estimated Annual Cost	$0.482 million/yr
Estimated Annual Emission Rate with SNCR Controls	62.9 tons/yr
NOx Emission Reduction	21 tons/yr
Control Cost Effectiveness	$23,000/ton
Selective Catalytic Reduction	
Estimated Capital Cost	$15.6 million
Estimated Annual Cost	$1.63 million/yr
Estimated Annual Emission Rate with SCR Controls	8.4 tons/yr
NOx Emission Reduction	75.5 tons/yr
Control Cost Effectiveness	$21,600/ton

The above NOx control measures are extremely expensive relative to the emissions reduction benefit. NVE does not consider these controls reasonably cost-effective.

Further details of the above estimated emissions are presented in Appendix B.

Time Necessary to Install Controls

State Implementation Plans (SIPs) are due to EPA by July 21, 2021. Sources are not expected to begin implementing controls until after the state's SIP has been approved by US EPA. After SIP approval, NVE would need time for design, permitting, procurement, installation and startup. Additionally, both the

[1] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

[2] Ibid.

above controls require the equipment be out of service. Therefore, the implementation schedule needs to allow for the unit's outage to accommodate regional electrical needs and other regionally affected utilities. Given these considerations, NVE estimates that implementing either of the above controls will require 2 to 3 years following SIP approval. If the SIP approval process is fairly quick, these controls could be on line by 2025. Therefore, compliance with any reduced NOx emissions rate could be achieved before the 2028 planning milestone.

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 N_2. 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.

The placement of SCR in the exhaust flow path of the boiler causes a backpressure which must be offset by increased electrical demand. This increased energy use is reflected in the economic analysis as one of the operating costs for SCR.

The 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 20 years after either of the above controls are implemented. The 20-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 shorter. Since this boiler is already over 40 years old, its actual remaining life is likely to be shorter than the 20 years following the date of installation of controls.

6.2 Tracy Unit 6 (Piñon Pine 4)

Cost of Implementing Emissions Controls

The Tracy Unit #6 could be retrofitted with either lean premix dry low NOx combustor or with selective catalytic reduction (SCR). Both are technically feasible controls for reducing NOx on this source.

NVE has estimated the costs for both these NOx control options and summarized the cost effectiveness in Table 3 below. 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 NVE that this estimate was still valid after adjusting for inflation. This GE DLN equipment cost estimate was escalated to 2019 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.

Annual operating costs for the DLN conversion were calculated for just one cost category - the annual costs for loss of capacity (turbine derate). GE estimates that this turbine's electrical generating capacity will decrease approximately 3.5% with DLN combustor verses the current steam injection. NVE has responsibility to have available capacity to meet system demands and would need to compensate for this lost generating capacity by purchasing capacity externally at a cost of $25/KW-month. This is the cost to have capacity available, regardless of whether it is used.

There are other types of operating costs associated with conversation of this unit to DLN burners which NVE has not quantified, and if included, would increase the costs of this control option. These include a higher fuel usage due to a change in the unit's heat rate due to the conversion and increased costs from the discontinuation of steam injection which hurts the plant's water balance.

The capital cost estimate for SCR for this turbine is based on a detailed price proposal provided 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. NVE 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.

Annual operating costs 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 assume that it is implemented as a standalone option without DLN Burners (e.g.; SCR with existing steam injection).

Table 3 – Tracy Unit #6/Piñon Pine 4 - NOx Control Option Cost-Effectiveness

Dry Low NOx Combustor Conversion	
Estimated Capital Cost	$12.78 million
Estimated Annual Cost	$2.08 million/yr
Estimated Annual Emission Rate with DLN	78 tons/yr
NOx Emission Reduction	135 tons/yr
Control Cost Effectiveness	$15,400/ton
Selective Catalytic Reduction (w/existing steam injection)	
Estimated Capital Cost	$7.68 million
Estimated Annual Cost	$1.41 million/yr
Estimated Annual Emission Rate with SCR	21.3 tons/yr
NOx Emission Reduction	192 tons/yr
Control Cost Effectiveness	$7,330/ton

For annualization of the capital cost, the remaining useful life/plant life was set as 20 years beyond the DLN or SCR installation date although the actual remaining life of this unit may be less.

Retrofitting this existing turbine with a new DLN combustor system is excessively expensive with an average cost-effectiveness over $15,000 per ton. The major cost element is the capital cost for the DLN combustor upgrade itself which costs over $12 million dollars capital. NVE does not consider this to be a reasonably cost-effective control relative to the environmental benefit.

Installing SCR is a somewhat less expensive option than the DLN conversion option because the existing HRSG has room within its physical structure to add SCR catalyst modules. Even so, the cost for this control option is over $7 million in capital costs and total annual costs of over $1.4 million per year including capital recovery. NV Energy considers these costs not reasonably cost-effective in the context of regional haze reasonable progress. Additionally, even without controls the total haze precursor emissions of this turbine (in tons/yr) divided by the distance to the nearest Class I area (in km) yields a Q/d of 2.7, which illustrates the minimal benefit to imposing controls. Further, as discussed in Appendix A, there are additional factors that support the conclusion that NOx controls at this generating station have minimal impact on nearby Class I areas.

An additional theoretical control option not shown above would be the implementation of both the SCR and the DLN conversion. Although this might provide a slight additional NOx reduction versus the SCR w/steam injection control option, it would have extremely higher costs (SCR w/DLN costs would be roughly equal to the sum of the costs of each of those options individually). A SCR w/DLN option's incremental cost relative to the incremental benefit is clearly prohibitive.

Further details of the above estimated emissions are presented in Appendix B.

Time Necessary to Install Controls

State Implementation Plans (SIPs) are due to EPA by July 21, 2021. Sources are not expected to begin implementing controls until after the state's SIP has been approved by US EPA. After SIP approval, NVE would need time for design, permitting, procurement, installation and startup. Additionally, both the above controls require the equipment be out of service. Therefore, the implementation schedule needs to allow for the unit's outage to accommodate regional electrical needs and other regionally affected utilities. Given these considerations, NVE estimates that implementing either of the above controls will require 2 to 4 years following SIP approval. If the SIP approval process is fairly quick, these controls could be on line by 2025 or 2026. Therefore, compliance with any reduced NOx emissions rate could be achieved before the 2028 planning milestone.

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 waste water stream that would require treatment or disposal. Currently, the steam injection system is integrated into the overall plant water balance. Process waste water is used to produce demineralized water for use in the steam injection system. Elimination of the steam injection will require additional investment in the water treatment system to dispose of the excess waste water. A DLN conversion will also decrease the electrical generation of the turbine because of the decreased mass flow. This lost power will need to be made up elsewhere.

Selective Catalytic Reduction results in an increase in the parasitic electrical load of the station. Placement of the SCR catalyst grid in the exhaust flow path of the boiler causes backpressure 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 is 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 N_2. 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.

The 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 20 years after any of the above controls are implemented. The 20 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 shorter.

7. Additional Considerations

Appendix A contains a review of additional issues relative to NOx emission controls for the Tracy Generating Station and concludes that the imposition of additional NOx controls on any of the units would have minimal benefit in terms of improved visibility at the closest Class 1 area, for the following reasons:

- EPA data for the Desolation Wilderness Area (the closest Class I area) shows that nitrate haze constitutes only a very small fraction of the total haze in this area;
- Nitrate haze formation, which is influenced by ambient temperature, is much higher in winter months than at other times of the year. As such, NOx emission reductions will only improve haze formation during the winter months and be relatively ineffective in terms of reducing haze formation at other times of the year;
- EPA modeling predicts that US anthropogenic emissions will have only a very small contribution to total haze at the Desolation Wilderness Area by the end of the Second Decadal Review period (2028), and that the adjusted glidepath indicates that the 2028 visibility goal is very close to being achieved using the baseline (2016 – 2018) emissions; and

- The Tracy Generating Station is northeast of nearby Class I areas which is typically downwind. Therefore, the emissions from Tracy would not impact the Class I areas most of the time.

8. Conclusions

Based on this initial review of the technical feasibility and costs associated with alternative emission controls, AECOM concludes that no further PM, NOx, or SO_2 controls beyond the current systems utilized on the Tracy Generating Station units are warranted for the following reasons:

- Units 1 and 2 have been permanently retired and yield over 300 tons/yr of NOx reductions by their retirement versus their BART allowed emissions rate from the first decadal period regional haze review.
- All the electrical generating units at Tracy burn only pipeline natural gas (excluding emergency needs) which minimizes SO_2 and PM_{10} emissions. There are no available technically-feasible emission control alternatives to provide further emissions reductions of these pollutants.
- Units 4 and 5 are NG-fired peaking turbines with NOx controlled to 9 ppm (at 15% O_2) with DLN combustors. Their good existing control combined with their limited utilization results in minimal annual emissions. No further controls would be reasonable.
- Units 8 and 9 are large NG-fired combined cycle turbines which are already equipped with DLN combustors and SCR achieving very low emissions. This is the highest level of control and no further control is feasible.
- Unit 3 is a pipeline natural gas-fired steam boiler. It has already implemented BART controls by eliminating the use of fuel oil and upgrading to Low-NOx Burners which achieve approximately 0.135 lb/MMBtu. Further controls are technically-feasible to reduce NOx by use of either SNCR or SCR. However, neither alternative is considered cost effective on this unit. The estimated cost-effectiveness for both SNCR and SCR exceeds $20,000/ton.
- Unit 6 (Piñon Pine #4) is a pipeline natural gas-fired combined cycle combustion turbine currently achieving approximately 41 ppm NOx (at 15% O2) using steam injection. 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. However, neither alternative is considered cost effective on this unit. The estimated cost-effectiveness for conversion of this unit to DLN is estimated to cost over $15,000/ton. The estimated cost-effectiveness for implementing SCR is over $7,000/ton. Moreover, as shown in Appendix A, the imposition of additional NOx controls would be expected to result in minimal, if any, improvements in visibility at even the closest Class I area to the station.

Since NV Energy is not proposing adding any additional controls, the 2016 – 2018 average emission rates, summarized in Table 1 (Section 4) can be used to estimate the emission levels from these units for the Second Decadal Review period. The existing emission control systems for these pollutants are concluded to represent reasonable progress for the units at the Tracy Generating Station.

Appendix A

Weight-of-Evidence 5th Factor Considerations for NOx Controls

EPA issued "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period"[3] in August 2019. This guidance allows States to consider, as part of its evaluation of emission controls to recommend for the Second Decadal Review, a "5th factor" which involves consideration of visibility impacts of candidate control options. A companion document[4] issued in September 2019 that involves EPA's visibility modeling results for 2028 is entitled, "Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling".

This appendix discusses four issues relative to NOx control options for the Tracy Generating Stations. This facility has its closest Class I area as Desolation Wilderness Area. Desolation Wilderness Area does not have an IMPROVE monitoring site. Instead, a nearby monitoring site at the Bliss State Park in California is representative of the Desolation Wilderness Area and is referenced in the discussion below. The issues involve:

1. The nitrate haze for the 20% worst days in recent years at the Interagency Monitoring of Protected Visual Environments (IMPROVE) site constitutes less than 5% of the total haze. Therefore, even elimination of all the NOx emissions in the United States would have only a very small effect upon the progress toward natural conditions in that area.

2. The nitrate haze is most prevalent in a few winter months (further discussed below), which implies that NOx emission controls (or restrictions in NOx emissions) during all the other months would not be very effective in reducing even the small component of haze due to NOx emissions.

3. Anthropogenic-related haze at the nearby Bliss State Park represents only a very small portion of total haze. Furthermore, EPA's modeling shows that Electrical Generating Unit (EGU) contributions to anthropogenic haze were not significant, which means that their contribution to total haze is exceedingly low for that area.

4. The amended glidepath analysis issued by EPA in their September 2019 modeling report (Appendix B) indicates that as of 2016, the current visibility conditions were close to the 2028 goals.

5. The Tracy Generating Station is east and north of all the nearby Class I areas. The prevailing winds are in the opposite direction. There is very little of the time that winds would carry Tracy emissions to the Class I areas, thus changes in its emissions would only have minimal benefit to Class I area visibility.

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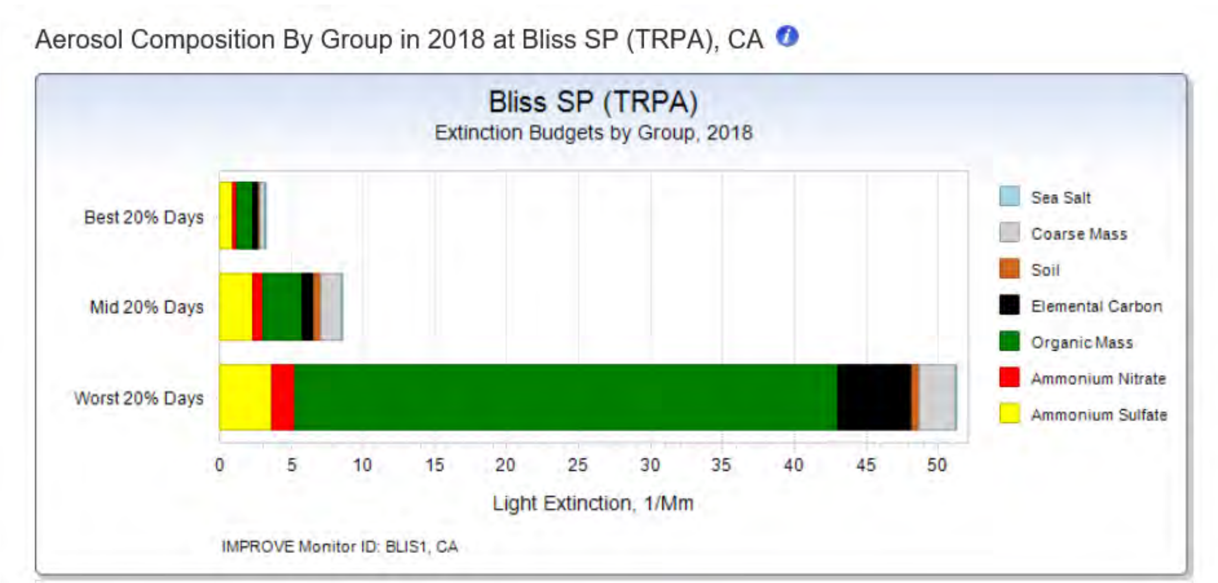
[3] Available at https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.
[4] Available at https://www3.epa.gov/ttn/scram/reports/2028_Regional_Haze_Modeling-Transmittal_Memo.pdf.

Nitrate Haze Composition Analyses

Nitrate Haze composition analyses for the Bliss State Park, the closest representative area for Desolation Wilderness, is available at the IMPROVE web site at http://vista.cira.colostate.edu/Improve/pm-and-haze-composition/. From that source, Figure A-1 provides a bar chart for haze composition by species for Bliss State Park for the latest available year of monitoring. It is clear from this figure that nitrate haze constitutes a very small fraction of the total haze for the worst 20% days. (Improving the 20% worse days are the focus of Regional Haze Rule Reasonable Progress goals.) Much of the haze composition for the worst-case days is due to wildfire emissions, which are the primary cause of organic mass and elemental carbon haze fractions and also contribute a portion of the nitrate haze fraction that is shown in the figure. Due to the low haze impact of anthropogenic NOx emissions at this location, Nevada would be justified to either remove NOx emissions controls completely from its consideration of Reasonable Progress steps for nearby sources or consider that only clearly affordable control options should be required.

Figure A-1: Composition Plot for Bliss State Park, 2018



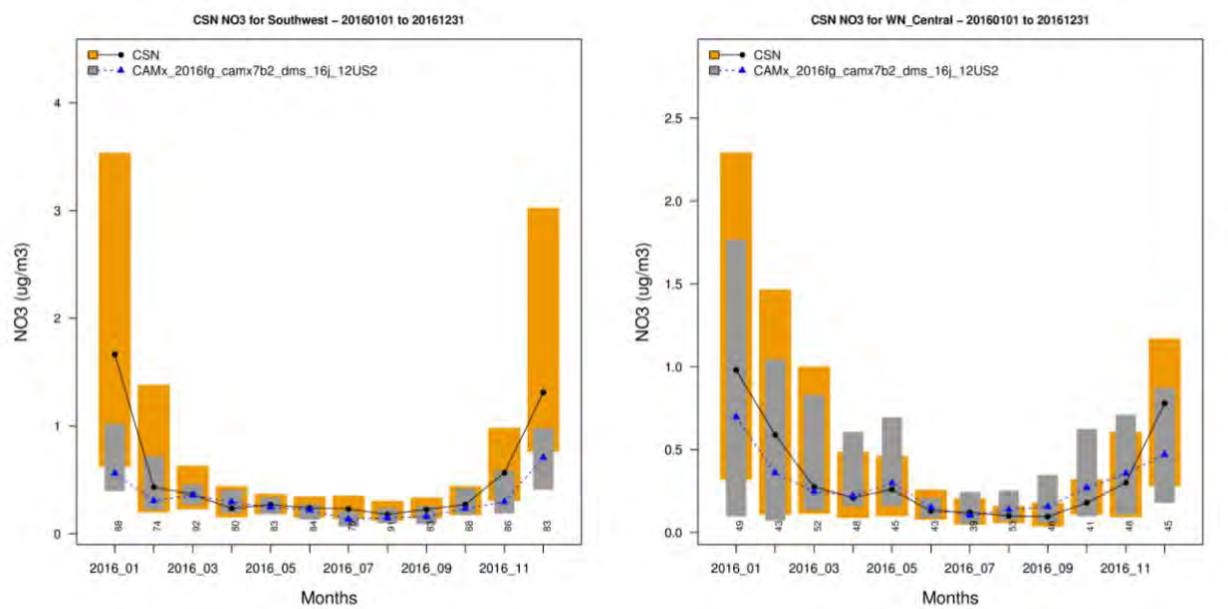
Wintertime Impacts of NOx Emissions from Modeling and IMPROVE Monitoring

The chemistry of nitrate haze formation is highly dependent upon ambient temperature and humidity. As discussed in the CALPUFF model formulation[5] and in CALPUFF course materials, total nitrate in the atmosphere ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous HNO_3 (invisible, and not haze-producing) and NO_3 haze particles according to the equilibrium relationship between the two species. This equilibrium is a strong function of ambient temperature and relative humidity.

[5] Documentation for the CALPUFF modeling system is available from links provided at https://www.epa.gov/scram/air-quality-dispersion-modeling-alternative-models#calpuff.

This dependency of nitrate haze formation as a function of temperature (and season) is shown in the September 2019 EPA modeling report referenced above in Figure A-2 (from Appendix A of that report). This figure shows that the kinetics of the nitrate haze equilibrium result in much higher particulate formation in winter compared to other seasons, while NOx emissions are expected to be relatively constant over the entire year. This implies that NOx emission reductions will only provide effective haze reduction for a few winter months of the year, and that such emission reductions in other months would be relatively ineffective. This is an additional reason to discount the relative value of NOx controls.

Figure A-2: Monthly Variation of Nitrate Particulate Concentration from EPA 2019 Modeling Report



<u>**Glidepath Status for Desolation Wilderness Areas and EGU contribution**</u>

Figure A-3 shows the EPA modeling report (for 2028 progress) glidepath status for Bliss State Park from Appendix B of the EPA document. The small "orange" portion of the SMAT2028 bar represents the total "US anthro" portion of haze by 2028 at this location and shows it is a very small fraction of the total. Additionally, the contribution of all EGUs are so small that the EGU component is not shown in the inserted pie chart as a significant anthropogenic contributor. Therefore, further emission controls on EGUs are expected to have a minimal benefit on visibility. Additionally, the adjusted glidepath indicates that the 2016 conditions are already close to attaining the 2028 goal. This is evidenced by the closeness of the adjusted glide path to the SMAT2028 bar. (Note: the MOD2016 and MOD2028 bars show that model overpredicts actual visibility and is useful only for relative contributions, but not absolute values.) Therefore, even if no additional controls on "US anthro" sources were requested, the modeling already indicates that the 2028 Reasonable Progress goal for Desolation will likely be met.

Figure A-5: EPA's September 2019 Modeling Report Glidepath Results for Desolation

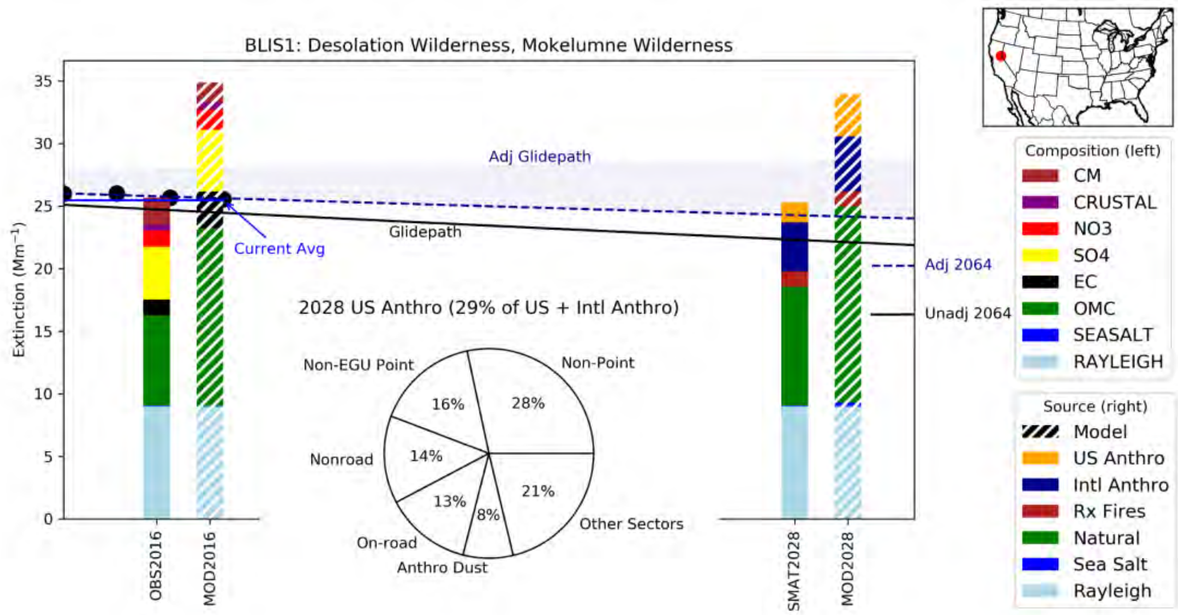


Figure 8: 2014-2017 IMPROVE observations, 2016 CAMx model predictions, 2028 modeled projection, and 2028 sector contributions at BLIS1. Used for Class I areas: Desolation Wilderness, Mokelumne Wilderness.

<u>Tracy is nominally downwind of nearby Class I areas.</u>

Figure A-4 shows that the Tracy Generating Station is east and north of all the nearby Class I areas and northeast of the closest, the Desolation Wilderness (81 km away). Accordingly, for emissions from the Tracy facility to blow towards these Class 1 areas, the wind would need to be coming from the east or northeast. However, these are the least common wind directions in the area. Instead, as shown in Figure A-5, which is a wind-rose of the meteorological data from the Reno airport[6], winds are much more commonly from the west, southwest or south. Consequently, further emission controls on the Tracy Generating Station would have a minimal benefit on visibility in these Class I areas.

[6] https://mesonet.agron.iastate.edu/sites/windrose.phtml?station=RNO&network=NV_ASOS

Figure A-4 Location of Tracy Generating Station and Class I Areas

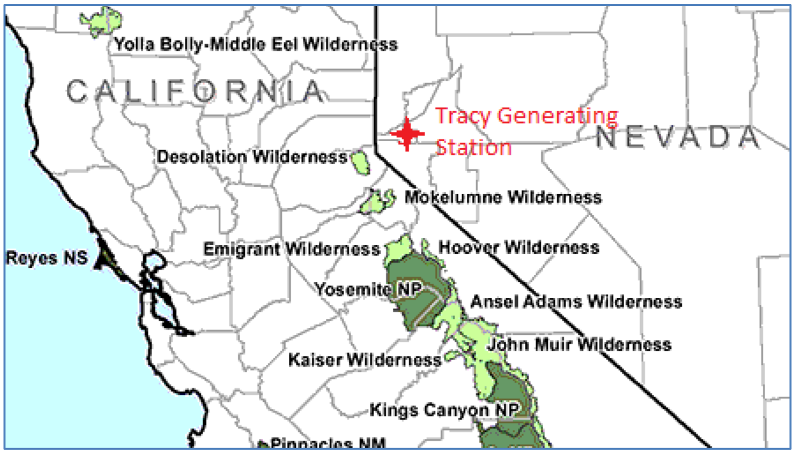
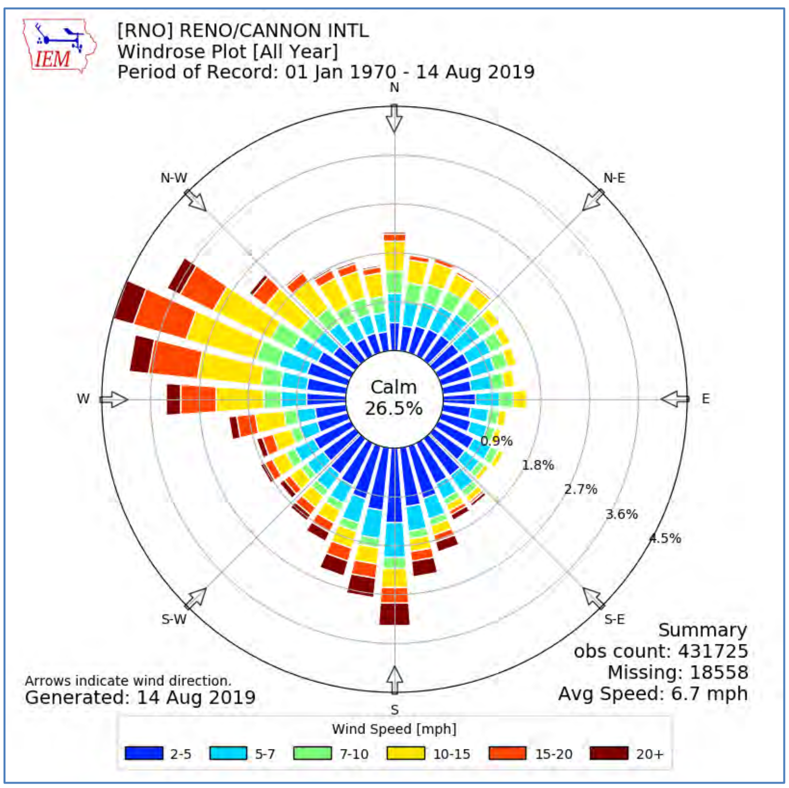


Figure A-5 Reno Airport Meteorological Wind Rose



Appendix B

Cost Estimate Details of Technical Feasible Control Options

SCR Cost Estimate for Tracy Unit 3 NG Boiler

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

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)?	113	MW
What is the higher heating value (HHV) of the fuel?	1,020	Btu/scf
What is the estimated actual annual MWhs output?	108,238	MWhs
Enter the net plant heat input rate (NPHR)	11.51	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 4413 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})	92 days	Calc. based on 2199 hrs/yr
Number of days the boiler operates (t_{plant})	92 days	
Inlet NO_x Emissions (NOx_{in}) to SCR	0.1347 lb/MMBtu	
Outlet NO_x Emissions (NOx_{out}) from SCR	0.01374 lb/MMBtu	90% control
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	5 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	20 Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Gas temperature at the SCR inlet (T)	750 ^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	1372 ft^3/min-MMBtu/hour

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	2019	
CEPCI for 2019	602.1 Enter the CEPCI value for 2019 541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7 Percent	From OAQPS Cost Manual Example, which is consistent or less than NVE internal cost of capital.
Reagent ($Cost_{reag}$)	0.400 $/gallon for 19% ammonia converted to 19% equiv.	
Electricity ($Cost_{elect}$)	0.0754 $/kWh	
Catalyst cost ($CC_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst	* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	73.36 $/hour (including benefits)	Labor Rate provided by NVE includes fringe.
Operator Hours/Day	4.00 hours/day*	* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Reagent Cost ($/gallon)	$0.293/gallon 29% ammonia solution	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf	Facilities would use 19% solution. Assume price of 19% is 19/29* price of 29%	Check with reagent vendors for current prices.
Electricity Cost ($/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 https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
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 year." Available at http://www.eia.gov/electricity/data/eia923/.
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 year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/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 =	1,301	MMBtu/hour	
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	989,880	MWhs	
Estimated Actual Annual MWhs Output (Boutput) =		108,238	MWhs	
Heat Rate Factor (HRF) =	NPHR/10 =	1.15		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.109	fraction	
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	958	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	89.8	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	157.32	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	75.35	tons/year	
NO_x removal factor (NRF) =	EF/80 =	1.12		
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	1,861,381	acfm	
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	456.54	/hour	
Residence Time	1/V_{space}	0.00	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 =	1.17		
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	0.0634	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})	4,077.14	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	1,939	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	2	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	2,230	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	47.2	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	44	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17 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} =	61	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	322	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	43	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	14,500	gallons (storage needed to store a 14 day reagent supply rounded 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	0.0944

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	672.25	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) =	$15,563,729	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$162,399	in 2019 dollars
Indirect Annual Costs (IDAC) =	$1,470,960	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,633,359	in 2019 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 =	$77,819 in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$16,470 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$48,551 in 2019 dollars
Annual Catalyst Replacement Cost =		$19,559 in 2019 dollars
	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	
Direct Annual Cost =		$162,399 in 2019 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	Cost) =	$1,744 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$1,469,216 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,470,960 in 2019 dollars

Direct Annual + Administr. $164,143

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,633,359 per year in 2019 dollars
NOx Removed =	75 tons/year
Cost Effectiveness =	$21,678 per ton of NOx removed in 2019 dollars

Actual expected emissions reduction 75.5 ton/yr at 90% control

SNCR Cost Estimate for Tracy Unit 3 NG Boiler

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
(June 2019)

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 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 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 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 0.015 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)? 113 MW

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? 108,238 MWh

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 11.25 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.

	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})	365 days	Plant Elevation	4413 Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.1347 lb/MMBtu		
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.101025 lb/MMBtu	25% control	
Estimated Normalized Stoichiometric Ratio (NSR)	1.05		

Concentration of reagent as stored (C_{stored})	19 Percent
Density of reagent as stored (ρ_{stored})	56 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	2019		
CEPCI for 2019	602.1 Enter the CEPCI value for 2019	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	7 Percent		
Fuel ($Cost_{fuel}$)	2.87 $/MMBtu*		
Reagent ($Cost_{reag}$)	0.400 $/gallon for a 19 percent solution of ammonia		
Water ($Cost_{water}$)	0.0042 $/gallon*		
Electricity ($Cost_{elect}$)	0.0754 $/kWh		
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	$/ton		

* 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	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)	$0.293/gallon of 29% Ammonia	U.S. Geological Survey, Minerals Commodity Summaries, January 2017 (https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf		Check with reagent vendors for current prices.
Water Cost ($/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.		Plant's utility bill or Black & Veatch's "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 ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.		Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at http://www.eia.gov/electricity/data.cfm#sales.
Fuel Cost ($/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.		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year. Available at http://www.eia.gov/electricity/data/eia923/.
Ash Disposal Cost ($/ton)	-	Not applicable	Not Applicable	Use plant data or use 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.
Percent sulfur content for Coal (% weight)	-	Not applicable	Not Applicable	Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year. Available at http://www.eia.gov/electricity/data/eia923/.
Percent ash content for Coal (% weight)	-	Not applicable	Not Applicable	Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year. Available at http://www.eia.gov/electricity/data/eia923/.
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 year. Available at http://www.eia.gov/electricity/data/eia923/.
Interest Rate (%)	5.5	Default bank prime rate		Use current bank prime rate available 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 =	1,271	MMBtu/hour	
Maximum Annual MWh Output =	Bmw x 8760 =	989,880	MWh	
Estimated Actual Annual MWh Output (Boutput) =		108,238	MWh	
Heat Rate Factor (HRF) =	NPHR/10 =	1.13		
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.11	fraction	
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	958	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	25	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	42.81	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	20.50	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 =	1.17		
Atmospheric pressure at 4413 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 =	56 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)	67	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	350	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	46.8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	15,800	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	0.0944

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	7.5	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	38	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.54	MMBtu/hour	
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1\text{x}10^6$)/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 ($SNCR_{cost}$) =	$1,468,701 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$1,768,438 in 2019 dollars
Total Capital Investment (TCI) =	$4,208,281 in 2019 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 ($SNCR_{cost}$) =	$1,468,701 in 2019 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 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})
For Coal-Fired Utility Boilers:
$BOP_{cost} = 320{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Utility Boilers:
$BOP_{cost} = 213{,}000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$
For Coal-Fired Industrial Boilers:
$BOP_{cost} = 320{,}000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$
For Fuel Oil and Natural Gas-Fired Industrial Boilers:
$BOP_{cost} = 213{,}000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$

Balance of Plant Costs (BOP_{cost}) =	$1,768,438 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$83,226 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$399,155 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$482,382 in 2019 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 =	\$63,124 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	\$17,927 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	\$543 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	\$151 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	\$1,482 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	\$0 in 2019 dollars
Direct Annual Cost =		\$83,226 in 2019 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$1,894 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$397,262 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$399,155 in 2019 dollars

Direct Annual + Administrative \$85,120

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$482,382 per year in 2019 dollars
NOx Removed =	20.5 tons/year
Cost Effectiveness =	\$23,528 per ton of NOx removed in 2019 dollars

Actual Expected NOx reduction 21 tpy at 25% control

Dry Low NOx Burner Conversion for Pinon Pine #4 (Unit 6)

Total Capital Investment (TCI)	**$12,783,364**	Equipment costs based on confidential January 2010 Vendor Budgetary Estimate for DLN conversion for this turbine.
TCI figure includes:		Costs escalated from 2010 to Aug. 2019 using CEPCI index (0.99%/yr)
Purchased Equipment and Instrumentation		
Sales Tax and Freight		Vendor costs include DLN Combustion Hardware, Gas Fuel Module, Control System, software modification, and tuning.
Direct Installation Costs		
Indirect Installation Costs (general facilities, engineering, contingency)		Freight, Direct Installation and Indirect Installation costs are based on factors from EPA OAQPS Cost Manual.

Annual Operating Costs

Capacity Loss from Derate

Capacity loss	4.43%	vendor estimate for DLN vs Stm inject.
Derate of Turbine	2.9	MW
Capacity Cost	25	$/KW per month capacity energy purchases
Derate annual Cost	**$870,000**	$/yr capacity energy purchases

Other Operating Costs not included are:

Heat Rate Impacts	TBD
Cost of Handling excess Water	TBD

Capital Costs Associated with SCR (Pinon Pine #4)(Unit 6)

	Cost Category		Cost Basis
	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
	Anxillary Equipment Price (Peerless)	$410,000	Other Anxillary Equipment (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
	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 Note 1)
	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	**$7,684,035**	A + B + C
	Notes: Capital Recovery Factor =	*0.0944*	*= i (1+ i)n/[(1+ i)n - 1]*
	(n) Equip Life years	*20*	
	(i) Interest Rate	*7%*	
	Capital Recovery Annualized ($/yr)	**$725,300**	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

Annual Operating Costs Associated with SCR (Pinon Pine #4)

Annual Operating Costs

Capacity Loss from Derate

Derate of Turbine only	0.56	MW (see bebow Electric. Cost)
Capacity Cost	25.00	$/KW per month capacity energy purchase cost per NVE
Derate annual Cost	$167,435	$/yr capacity energy purchases (represents cost to have capacity available - whether it is used or not) (Separate from elect. cost debit to overcome SCR pressure drop)

Power Cost due to 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)	0.84774194	annual MMBTU/MW/10
Bmw	107	Unit Megawatt rating (Nominal Output)
Power demand/loss	558	kW (per above formula)
Electricity Price	0.0754	$/kWh standard value in EPA SCR cost sheet
Annual Utilization	42%	
Annual cost	$154,828	$/yr

Catalyst Changeout Cost based on Future worth Factor (FWF)

Changeout	5	yrs
Interest Rate	7%	
Calc. FWF	0.174	
SCR Cost per Changeout	$1,100,000	cost per recent NVE Silverhawk SCR catalyst replacement
SCR Annual Cost	$191,000	using EPA forward worth factor (FWF) methodoloy

Annual Maintenance Costs

Annual Maintenance Costs 0.005 * TCI	$38,420	From SCR OAQPS Cost Manual and Spreadsheet.

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	gal/hr
Ammonia Solution concentration	19%	%
Ammonia use at 19% solution	15.583	gal/hr
19% Ammona Solution Cost	0.95	$/gal NVE past year costs $0.89/gal, expect 2020 price slight increase to $0.95/gal.
Annual Cost	$129,684	

Total of Above Annual Operating Costs	**$681,367**	Does not include Capital Recovery

Regional Haze Reasonable Further Progress Four Factor Analysis

NV Energy North Valmy Generating Station

AECOM Project Number: 60619218

Prepared for:

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March 2020

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 in order to continue a reasonable rate of progress in visibility improvement. NDEP identified the North Valmy Generating Station as a source 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 rules, the analysis needs to first identify all 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

Additionally, consideration of a fifth factor, evaluation of the visibility benefits of each option, is not required, but states may consider visibility in addition to the four statutory factors when making their reasonable progress determinations.

Accordingly, this report presents NV Energy's evaluation of the emissions rates and potential emission controls for the North Valmy Generating Station. This report provides a description of the facility (Section 2), a summary of the actions taken during First Decadal Review period of the Regional Haze Rule (Section 3), a summary of each unit's baseline emissions (Section 4), 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. Additionally, the report includes two appendixes: Appendix A is provided for NDEPs consideration with general information about limitations associated with reducing nitrogen oxide emissions in terms of improving visibility impacts at the nearby Class I areas, and Appendix B consists of Idaho Power Company's recent Public Utility Commission filing addressing their commitment to cease coal burning operation of at North Valmy.

1.1 Facility Description

1.1.1 General

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.

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 nitrogen oxide (NOx) emissions through the use of Low NOx burners and overfired air.

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 (Low NOx burners and overfire air) to control NOx emissions, and a lime slurry-based spray dryer to control sulfur dioxide (SO_2) emissions.

1.1.2 Station Operational Considerations

The North Valmy Generating Station is jointly owned by Sierra Pacific Power Company d/b/a NV Energy and Idaho Power Company (“Idaho Power”), with each owner having a 50 percent ownership share in the station’s (or unit) net generating capacity to the extent the capacity is available. Historically, either owner could schedule unused capacity of the other owner for the purpose of meeting its own system loads, subject to notification to the owner and corresponding usage charges.

On May 31, 2017, the Idaho Public Utilities Commission accepted and approved a Settlement Stipulation executed by Idaho Power and others in which Idaho Power agreed to use prudent and commercially reasonable efforts to negotiate with NV Energy to accomplish a permanent end to coal-burning operations at North Valmy Unit 1 by December 31, 2019, and at Unit 2 by December 31, 2025, or, in the alternative, to use prudent and commercially reasonable efforts to end its participation in the operation of Unit 1 by December 31, 2019, and of Unit 2 by December 31, 2025. NV Energy and Idaho Power subsequently entered into an agreement in 2019 that facilitated Idaho Power’s ability to end its participation in Units 1 and 2 in accordance with their settlement. This agreement contractually limits the capacity of Unit 1 to NV Energy’s 50% share, except for periods which full load testing is required for compliance or functional testing. This agreement was approved by each owner’s respective commissions in 2019. Idaho Power subsequently ended its participation in Unit 1 on December 31, 2019.

Accordingly, as is the case for Unit 1 now and will be the case for Unit 2 in the year 2026 and beyond, the North Valmy units will only be serving NV Energy’s load, not Idaho Power’s. This practical limitation on the output of the Station has resulted in reduced forecasted output for the Station relative to the recent historical output.

EPA’s 2019 Guidance on Regional Haze State Implementation Plans for the Second Implementation Period describes the process that is to be followed for estimating future emissions. The guidance refers to the primary goal of making projections of future emissions that account for key variables likely to impact emission estimates, and accordingly it allows for consideration of factors that are likely to increase or decrease the future operation of emission units. One of the factors that may serve as reasonable basis for projecting a change in historic operating parameters mentioned in the guidance is that of “such programs where there is a documented commitment to participate” as well as “a verifiable basis for quantifying any change in future emissions due to operational changes”. In this context, Idaho Power’s ownership decision to cease coal burning operations at North Valmy, as documented by both Idaho’s and Nevada’s respective Public Utility Commissions (see Appendix B), meets the defined criteria for consideration of reduced output projections.

For planning purposes, NV Energy has forecast the anticipated future output of the North Valmy Station for the Nevada Public Utilities Commission in a 2018 Integrated Resource Plan (IRP) filing. The projected future operation at North Valmy considers Idaho Power’s exit from both units, as well as several other factors such as demand growth, integration of renewable energy projects currently under development to meet Nevada’s mandated Renewable Portfolio Standard (RPS), and the expiration of existing energy purchase contracts. While this 2018 IRP forecast is the most reasonable and technically credible estimate of expected future output from North Valmy (and therefore for future-year emissions estimates), NV Energy has assumed a more conservative projection for this analysis that only considers the reduction of Idaho Power’s portion of facility output from the 2016-2018 baseline period. As Idaho Power’s portion of net generation during that time was 33.6% of the total facility output, the future projections for 2028 have been estimated as equal to the output of the 2016-2018 baseline years minus Idaho Power’s net generation. Therefore, station output for 2028—the end of the Second Decadal regional haze review/implementation period—is forecast to be 691,664 MWhr/yr (15.8% annualized capacity factor). As described further in Section 5, this projected future output of the station has been utilized to develop the operating costs associated with candidate NOx and SO_2 control options.

2. First Regional Haze Planning Period Reasonable Progress Determination

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 between August 7, 1962 and August 7, 1977 were eligible for consideration for Best Available Retrofit Technology (BART) emission controls during this review period. Neither Unit 1 nor Unit 2 were operating during this period.

3. Baseline Emissions Summary

The following table summarizes the 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. NOx and SO_2 emissions are those reported through the EPA Air Markets program; PM emissions are taken from the annual emission reports that NV Energy has provided to the NDEP. The baseline period encompasses the 2016 through 2018 calendar years, as discussed with the NDEP on December 3, 2019.

Table 1 – North Valmy Generating Station – Average 2016-2018 Emissions from Combustion Sources

	SO2	NOx	PM
Baseline Emission Rates for Unit 1			
2016	1,848 ton/yr	797 ton/yr	22.01 ton/yr
2017	1,232 ton/yr	587 ton/yr	16.27 ton/yr
2018	2,357 ton/yr	1,027 ton/yr	27.76 ton/yr
2016 – 2018 Annual Average	1,812 ton/yr 0.760 lb/MMBtu	804 ton/yr 0.337 lb/MMBtu	22.01 ton/yr 0.0092 lb/MMBtu
Baseline Emission Rates for Unit 2			
2016	431 ton/yr	839 ton/yr	54.84 ton/yr
2017	356 ton/yr	674 ton/yr	20.97 ton/yr
2018	716 ton/yr	1,493 ton/yr	37.19 ton/yr
2016 – 2018 Annual Average	501 ton/yr 0.158 lb/MMBtu	1,002 ton/yr 0.317 lb/MMBtu	37.67 ton/yr 0.0119 lb/MMBtu

4. Identification of Potentially Feasible Emission Controls

To begin a four-factor analysis, it is first necessary 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. 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 Sulfur Dioxide Emission Control Options

As described previously, North Valmy Unit 2 is equipped with a lime slurry-based spray dryer to control SO_2 emissions. Unit 1 is not equipped with an active SO_2 control system. Average actual SO_2 emissions for the 2016 to 2018 period were 0.760 lb/MMBtu for Unit 1 and 0.158 lb/MMBtu for Unit 2.

Both limestone- and lime-based flue gas desulfurization (FGD) systems were evaluated as technically feasible alternatives for reducing SO_2 emissions from Unit 1. No technically-feasible control options that provide for lower SO_2 emissions from Unit 2 were identified.

4.2 Particulate Matter Emission Control Options

There are no technically-feasible emission control alternatives available to reduce particulate matter emissions below the emission levels achieved using the baghouse filters that are currently employed on North Valmy Units 1 and 2.

4.3 Nitrogen Oxides Emission Control Options

As noted above, both North Valmy Unit 1 and Unit 2 are currently configured for multi-stage combustion, including the use of low NOx burners, to control NOx emissions. Per Table 1, average actual NOx emissions for the 2016 to 2018 period were 0.337 lb/MMBtu for Unit 1 and 0.317 lb/MMBtu for Unit 2. Selective Non-catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR) were evaluated as technically feasible options on these units capable of achieving NOx emission rates lower than with the current multi-stage combustion controls. 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. On coal fired electric generating units, the catalyst grid is typically installed between the boiler's economizer and air preheater. For retrofit applications (such as would be required for North Valmy Units 1 and 2), duct work must be installed to transport flue gas from the economizer exit to the SCR reactor and then back to the air preheater inlet. For this reason, retrofit applications of SCR can be difficult due to space and other physical constraints. The preferred flue gas temperature range within the catalyst is 650 °F to 725 °F. In some cases, an economizer bypass is required to maintain the required temperature, especially at low load.

If installed on these units, the NOx control performance of SNCR is estimated at 25% based on Figure 1.1b in EPA's Control Cost Manual[1]. If the units were to be equipped with SCR, their NOx control performance is projected to be 78% based on BART determinations of emission rates from the initial regional haze planning period.

5. Four Factor Analysis

The previous section presented an analysis of the control alternatives that are potentially feasible to lower the emissions of NOx or SO_2 from the emission units at the North Valmy Generating Station. The

[1] EPA Air Pollution Control Cost Manual, Section 4 (NOx Controls) Chapter 1: "Selective Noncatalytic Reduction," April 2019

identified control options for further evaluation in order to reduce regional haze for these units are as follows:

North Valmy Unit 1 Potential Control Options:

- NOx: Selective Non-Catalytic Combustion (SNCR) or Selective Catalytic Reduction (SCR)
- SO_2: Limestone- and lime-based flue gas desulfurization (FGD).

North Valmy Unit 2 Potential Control Options:

- NOx: Selective Non-Catalytic Combustion (SNCR) or 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 Cost of Implementing Controls

5.1.1 NOx Controls - North Valmy Unit 1

As noted above, SNCR and SCR are both technically feasible alternatives for reducing NOx emissions from this source.

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 this alternative would likely be relatively straightforward.

Similarly, the capital and annualized costs for SCR were estimated using the SCR Cost Calculation Spreadsheet in EPA's Control Cost Manual[3]. A retrofit factor of 1.3 was used for this alternative, reflecting the severe limitations on available space in the vicinity of Unit 1, the need for new steel structures to be built to support the SCR equipment, capacity limitations on the unit's existing forced draft and induced draft fans, 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.

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[2] EPA Air Pollution Control Cost Manual, Section 4 (NOx Controls) Chapter 1: "Selective Noncatalytic Reduction," April 2019

[3] EPA Air Pollution Control Cost Manual, Section 4 (NOx Controls) Chapter 2: "Selective Catalytic Reduction," June 2019

For annualization of the capital cost for either alternative, the remaining useful life/plant life was set as 20 years beyond the emission control system installation date.

As described above in Section 1.1.2, the electrical output from the North Valmy Generating Station at the end of the Second Decadal regional haze review/implementation period is projected to be significantly lower than in the baseline period largely as a result of Idaho Power's exit from the units. Consequently, potential emission reductions that can be realized by candidate emission control alternatives in the 2028 timeframe will be lower than during the baseline period. Accordingly, the cost effectiveness of these alternatives has been evaluated based on the projected station output and corresponding uncontrolled emission levels associated with the forecasted output of the North Valmy Station in 2028.

Table 2 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 C.

Table 2 – North Valmy Unit 1 - NOx Control Option Cost Summary

Selective Non-Catalytic Reduction	
Estimated Capital Cost	$9.18 million
Estimated Annual Cost	$1.28 million/yr
NOx Emission Reduction with SNCR Controls	134 tons/yr
Control Cost Effectiveness	$9,512/ton
Selective Catalytic Reduction	
Estimated Capital Cost	$111.1 million
Estimated Annual Cost	$12.13 million/yr
NOx Emission Reduction with SCR Controls	425 tons/yr
Control Cost Effectiveness	$28,583/ton

The above NOx control measures are extremely expensive relative to the emissions reduction benefit. Accordingly, NV Energy does not consider either of the technically-feasible NOx control alternatives for North Valmy Unit 1 to be cost-effective.

5.1.2 SO_2 Controls – North Valmy Unit 1

Limestone- and lime-based FGD systems are both technically feasible alternatives for reducing SO_2 emissions from North Valmy Unit 1.

In 2009, NV Energy commissioned an evaluation by the engineering firm Sargent & Lundy (S&L) on the technical feasibility and costs associated with retrofitting an FGD system on North Valmy Unit 1. S&L identified two technology options for this system: the forced oxidation FGD process employing either limestone or lime as the calcium source. Each option involves contacting hot flue gas from the boiler's economizer with a water slurry of either limestone or lime in a vertical absorber/reaction vessel. SO_2 in the boiler flue gas is absorbed into the slurry and converted to calcium sulfate ($CaSO_4$) and calcium sulfite ($CaSO_3$). An oxidizing environment is maintained in the reaction portion of the vessel with compressed air being introduced in order to preferentially promote production of calcium sulfate. A slurry of calcium sulfate is continuously removed from the reaction vessel, and subsequently dewatered and either disposed of in onsite surface impoundments or sent offsite for disposal. In either event, the disposal of waste solids associated with FGD system operation would need to conform to the recent amendments to EPA's regulations for disposal of coal combustion residuals (CCR)[4].

For this analysis, the cost estimates for the two FGD options presented in the S&L study were updated to reflect current (late 2019) capital costs using standard engineering cost estimating methods, including the use of the Chemical Engineering Plant Cost Index (CEPCI) to escalate equipment and installation costs, the US Bureau of Labor Statistics (BLS) Employment Cost Index to escalate construction labor costs, and the BLS Producer Price Index along with raw material usage rates to estimate annual costs associated with FGD system reagent. Estimated costs for solid waste disposal utilize the same unit cost factor employed in the S&L study, however the use of this factor likely results in an underestimate of the true cost of solid waste disposal, because the S&L study was conducted prior to the CCR rule amendments having been finalized. A site-specific estimate of the cost associated with disposing of FGD solids in conformance with the updated CCR rule requirements was not conducted for this report, and therefore the additional cost associated with meeting the CCR rule requirements is not known at this time.

As with the NOx control alternatives described above, annualization of the capital cost for either FGD alternative was estimated using an estimated 20-year useful life of the plant beyond the emission control system installation date. Annualized cost effectiveness of these alternatives was also estimated based on the projected output of the unit in 2028.

Table 3 summarizes the estimated capital costs, annual costs, and cost effectiveness associated with the two FGD SO_2 control options for North Valmy Unit 1. Details of these cost estimates are provided in Appendix C.

[4] 83 FR 36435, "Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One)."

Table 3 – North Valmy Unit 1 – SO_2 Control Option Cost Summary

Limestone-based Flue Gas Desulfurization	
Estimated Capital Cost	$247.8 million
Estimated Annual Cost	$26.9 million/yr
SO_2 Emission Reduction with Limestone FGD	1,169 tons/yr
Control Cost Effectiveness	$23,008/ton
Lime-based Flue Gas Desulfurization	
Estimated Capital Cost	$238.2 million
Estimated Annual Cost	$26.0 million/yr
SO_2 Emission Reduction with Lime FGD	1,169 tons/yr
Control Cost Effectiveness	$22,252/ton

Either SO_2 control alternative would be extremely costly to implement and the emission reduction potential that could be realized is relatively modest considering the projected future utilization of North Valmy Unit 1. Therefore, NV Energy does not consider either of these SO_2 control alternatives to be cost-effective for North Valmy Unit 1.

5.1.3 NOx Controls - North Valmy Unit 2

As noted above, SNCR and SCR are both 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 annualized costs for SCR were estimated as described above for Unit 1 using EPA's Control Cost Manual and a retrofit factor of 1.3. As with Unit 1, the remaining useful life/plant life was set as 20 years beyond the emission control system installation date for annualization of the capital cost for either alternative. Cost effectiveness for each alternative was estimated using the projected station output and corresponding uncontrolled emission levels associated with the 2028 projection.

Table 4 summarizes the estimated capital and annual costs for these control methods. Details of these cost estimates are provided in Appendix C.

Table 4 – North Valmy Unit 2 - NOx Control Option Cost Summary

Selective Non-Catalytic Reduction	
Estimated Capital Cost	$9.75 million
Estimated Annual Cost	$1.41 million/yr
NOx Emission Reduction with SNCR Controls	164 tons/yr
Control Cost Effectiveness	$8,588/ton
Selective Catalytic Reduction	
Estimated Capital Cost	$128.9 million
Estimated Annual Cost	$14.1 million/yr
NOx Emission Reduction with SCR Controls	511 tons/yr
Control Cost Effectiveness	$27,559/ton

As with Unit 1, NV Energy does not consider either of the technically-feasible NOx control alternatives for North Valmy Unit 2 to be cost-effective.

5.2 Time Necessary to Install Controls

State Implementation Plans (SIPs) that address emission reductions needed to achieve regional haze improvements are due to EPA by July 21, 2021. Sources are not expected to begin implementation of any additional mandated controls until after the state's SIP has been approved by US EPA. After SIP approval, NV Energy would need time for design, permitting, procurement, installation and startup of any new emission control systems at the North Valmy Generating Station. Electric utilities generally anticipate that it would take between 6 and 8 years to implement emission controls at existing facilities with challenging equipment retrofit issues like the North Valmy Generating Station. The more complex the retrofit issues and their associated unknowns, the longer the engineering, procurement, and installation phases of the project will take. An extended equipment retrofit timeline at North Valmy should be expected given the number, range and complexity of the retrofit issues at this facility.

Additionally, installing any of the alternative NOx or SO_2 controls on these units would require that the generating equipment be out of service during construction and startup phases of implementation. Therefore, the schedule for implementation of emission controls needs to allow for the units' outage to accommodate regional electrical needs and other regionally affected utilities. In general, NV Energy estimates that implementing either of the above control options would require at least 6 years following SIP approval. If the SIP approval process occurs fairly quickly, these controls could be on line by mid-2028. Therefore, it is anticipated that compliance with any mandated reduction in NOx or SO_2 emissions at North Valmy would very likely only be achieved near the end of the Second Decadal Review period.

5.3 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 in order 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. However, with proper system design and operation, these safety issues are considered manageable.

Retrofitting SCR to either Unit 1 or 2 would be expected to result in an increase in the parasitic electrical load of the station. 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. This increased energy use is reflected in the economic analysis as one of the operating costs for SCR.

With respect to the SO_2 control alternatives, both limestone- and lime-based FGD produce solid waste, consisting of a largely dry solid product (generally around 85% solids) containing the desulfurization reaction products calcium sulfate and calcium sulfite. The estimated solid waste generation rate for the limestone FGD alternative is 3,150 tons/yr; for the lime FGD alternative the estimated waste generation rate is 3,242 tons/yr. FGD solid waste is considered CCR subject to EPA's CCR disposal rules.

Either FGD option would also consume water via evaporative losses that will occur when the hot boiler flue gas contacts the FGD reagent slurry. Estimated water losses are over 61,000 gallons per day for the for the limestone FGD alternative and over 53,000 gallons per day for the lime FGD alternative.

Electricity use at the station would increase with implementation of either FGD alternative, associated with reagent slurry makeup and handling, waste product handling, compressed air supply, and backpressure on the unit's flue gas system associated with the pressure drop across the FGD absorber/reaction vessel.

The increased energy use, water use, and waste generation have all been accounted for in the economic assessment of these alternatives summarized previously.

5.4 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 will continue to operate at least 20 years after any of the technically feasible control alternatives were to be implemented. The 20-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 shorter. Nonetheless, considering that both Unit 1 and Unit 2 are already nearly 40 years old, their actual remaining life is likely to be shorter than the 20 years following 2028 that was assumed for the economic analysis of emission control options.

5.5 Additional Considerations

Appendix A contains a review of additional issues relative to NOx emission controls for the North Valmy Generating Station, and concludes that the imposition of additional NOx controls on Units 1 and 2 would have minimal benefit in terms of improved visibility at the closest Class 1 area, for the following reasons:

- EPA data for the Jarbidge Wilderness Area shows that nitrate haze constitutes a very small fraction of the total haze in this area,
- Nitrate haze formation, which is influenced by ambient temperature, is much higher in winter months than at other times of the year. As such, NOx emission reductions will only improve haze formation during the winter months and be relatively ineffective in terms of reducing haze formation at other times of the year,
- 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, and
- Using the baseline (2016 – 2018) emissions, the adjusted glidepath indicates that the 2028 visibility goal has already been achieved at the Jarbidge Wilderness Area. Even if no additional emission controls were to be installed on the North Valmy Station, reasonable progress goals will likely be met by the target date.

6. Conclusions

Based on this review of the technical feasibility and costs associated with alternative emission controls, AECOM concludes that no further PM, NOx, or SO_2 controls beyond the current systems utilized on the North Valmy Generating Station Units 1 and 2 are warranted, for the following reasons:

- Particulate matter emissions from both Units 1 and 2 are already controlled by baghouse filters to levels that are considered equivalent to the most stringent achievable on this source type. There are no technically-feasible emission control alternatives available to reduce particulate matter emissions below the emission levels currently achieved.
- SNCR and SCR are technically-feasible alternatives for control of NOx emissions from Units 1 and 2. However, both alternatives are found to be cost-prohibitive and would result in additional adverse environmental and energy impacts. Moreover, as shown in Appendix A, the imposition of additional NOx controls on Units 1 and 2 would be expected to result in minimal, if any, improvements in visibility at the closest Class I area to the station.
- SO_2 emissions from Unit 2 are controlled with a lime slurry-based spray dryer system, and there are no technically-feasible alternatives that are available to reduce SO_2 emissions below the level currently achieved by this system.

- Both limestone- and lime-based FGD systems are technically feasible SO_2 emission control alternatives for Unit 1, however either alterative would be cost-prohibitive and result in additional adverse environmental and energy impacts.

Accordingly, the PM, NOx, and SO2 emission levels achieved using the existing emission control systems for these pollutants are concluded to represent reasonable progress for North Valmy Units 1 and 2.

NV Energy is not proposing to install any additional emission controls on either of the units at the North Valmy Generating Station. The facility's 2016 – 2018 average emission rates, summarized in Table 1 (see Section 4) represent historical operating conditions that are not indicative of future operations given Idaho Power's documented ownership decisions. Therefore, they do not represent projected future output of the facility's expected emission levels from these units for the Second Decadal Review period. Emission estimates that correspond to the projected facility output for 2028 that account for the reduction of Idaho Power's portion of net generation from the baseline period are more realistic projections of actual emissions that will occur during this period. The estimated annual average emission rates for this period for Units 1 and 2 are summarized in Table 5.

Table 5 – North Valmy Generating Station – Projected Annual Emissions for 2028

	Unit 1	Unit 2
Sulfur Dioxide (ton/yr)	1,210	327
Nitrogen Oxides (ton/yr)	537	657
Particulate Matter (ton/yr)	14.7	24.7

Appendix A

Weight-of-Evidence 5th Factor Considerations for NOx Controls

EPA issued "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period"[5] in August 2019. This guidance allows States to consider, as part of its consideration of emission controls to recommend for the Second Decadal Review, a "5th factor" which involves consideration of visibility impacts of candidate control options. A companion document[6] issued in September 2019 that involves EPA's visibility modeling results for 2028 is entitled, "Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling".

This appendix introduces four issues relative to NOx control options for the North Valmy Generating Station, which has Jarbidge Wilderness Area as its closest Class I area. The issues involve:

1) The nitrate haze for the 20% worst days in recent years at the Jarbidge Interagency Monitoring of Protected Visual Environments (IMPROVE) site constitute less than 5% of the total haze. Therefore, elimination of all NOx emissions in the United States would have only a very small effect upon the progress toward natural conditions in this Class I area.

2) The nitrate haze is most prevalent in a few winter months (further discussed below), which implies that NOx emission controls (or restrictions in NOx emissions) during the all the other months would not be very effective in reducing even the small component of haze due to NOx emissions.

3) 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, and

4) Using the baseline (2016 – 2018) emissions, the adjusted glidepath indicates that the 2028 visibility goal has already been achieved at the Jarbidge Wilderness Area. Even if no additional emission controls were to be installed on the North Valmy Station, reasonable progress goals will likely be met by the target date.

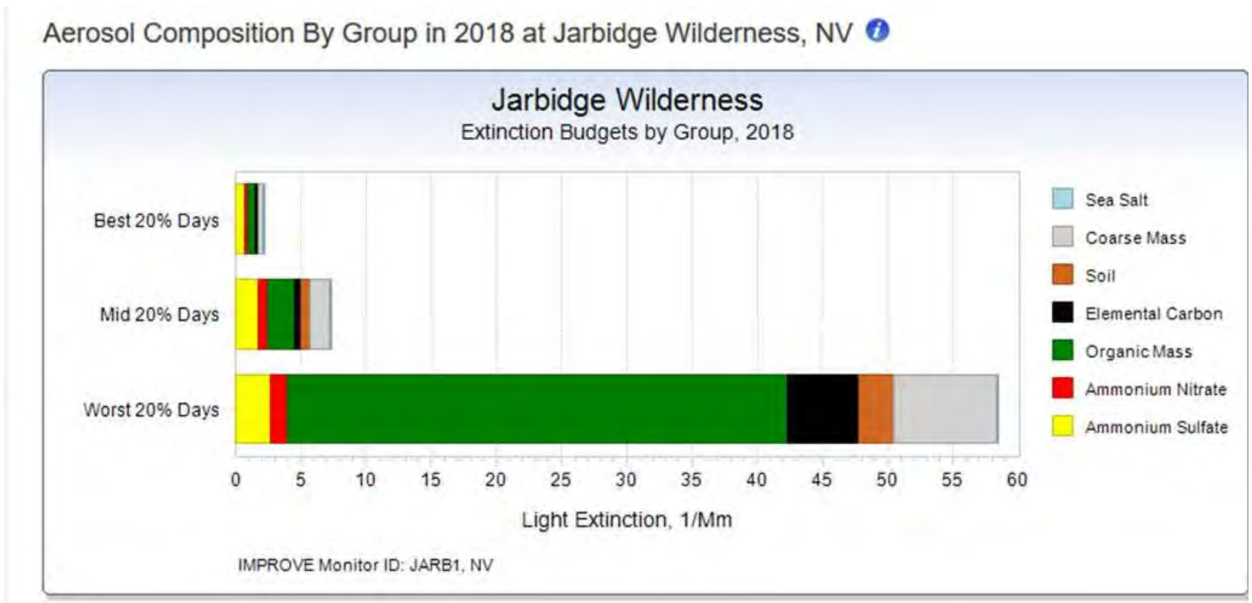
Nitrate Haze Composition Analyses

Nitrate Haze composition analyses for the Jarbidge Wilderness Area is available at the IMPROVE web site at http://vista.cira.colostate.edu/Improve/pm-and-haze-composition/. Figure A-1 provides a bar chart for haze composition by species for Jarbidge Wilderness Area for the latest available year of

[5] Available at https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.
[6] Available at https://www3.epa.gov/ttn/scram/reports/2028_Regional_Haze_Modeling-Transmittal_Memo.pdf.

monitoring. It is clear from this figure that nitrate haze constitutes a very small fraction of the total haze for the worst 20% days, which is the issue for improvement that the Regional Haze Rule focuses upon for Reasonable Progress. Much of the haze composition for the worst-case days is due to wildfire emissions, which are the primary cause of organic mass and elemental carbon haze fractions and also contribute a portion of the nitrate haze fraction that is shown in the figure. Due to the low haze impact of anthropogenic NOx emissions at this area, Nevada should either remove NOx emissions controls completely from its consideration of Reasonable Progress steps for North Valmy, or consider that only clearly affordable control options should be required.

Figure A-1: Composition Plot for Jarbidge Wilderness Area, 2018



Wintertime Impacts of NOx Emissions from Modeling and IMPROVE Monitoring

The chemistry of nitrate haze formation is highly dependent upon ambient temperature and humidity. As discussed in the CALPUFF model formulation[7] and in CALPUFF courses, total nitrate in the atmosphere ($TNO_3 = HNO_3 + NO_3$) is partitioned into gaseous HNO_3 (invisible, and not haze-producing) and NO_3 haze particles according to the equilibrium relationship between the two species. This equilibrium is a strong function of ambient temperature and relative humidity.

This dependency of nitrate haze formation as a function of temperature (and season) is shown in the September 2019 EPA modeling report referenced above in Figure A-2 (from Appendix A of that report). This figure shows that the kinetics of the nitrate haze equilibrium result in much higher particulate formation in winter compared to other seasons. This implies that NOx emission reductions will only provide effective haze reduction for a few winter months of the year, and that such emission reductions in other months would be relatively ineffective.

[7] Documentation for the CALPUFF modeling system is available from links provided at https://www.epa.gov/scram/air-quality-dispersion-modeling-alternative-models#calpuff.

Moreover, as shown in Figure A-3 the North Valmy units are disproportionately operated in the late spring and summer. Operating data from the 2016 – 2018 baseline period shows that >76% of the time the units were in operation was in the warmer months (April – September). Less than 25% of the total operating time of the units during baseline period was in the cooler months (October – March) when nitrate haze formation occurs. This operational pattern is not expected to change because the output at North Valmy varies in response to regional electricity demand.

Accordingly, the difference between when the bulk of NOx emissions from the North Valmy units occur and when nitrate haze formation will occur as a result of those emissions is an additional reason to discount the relative value of NOx controls for these units.

Figure A-2: Monthly Variation of Nitrate Particulate Concentration from EPA 2019 Modeling Report

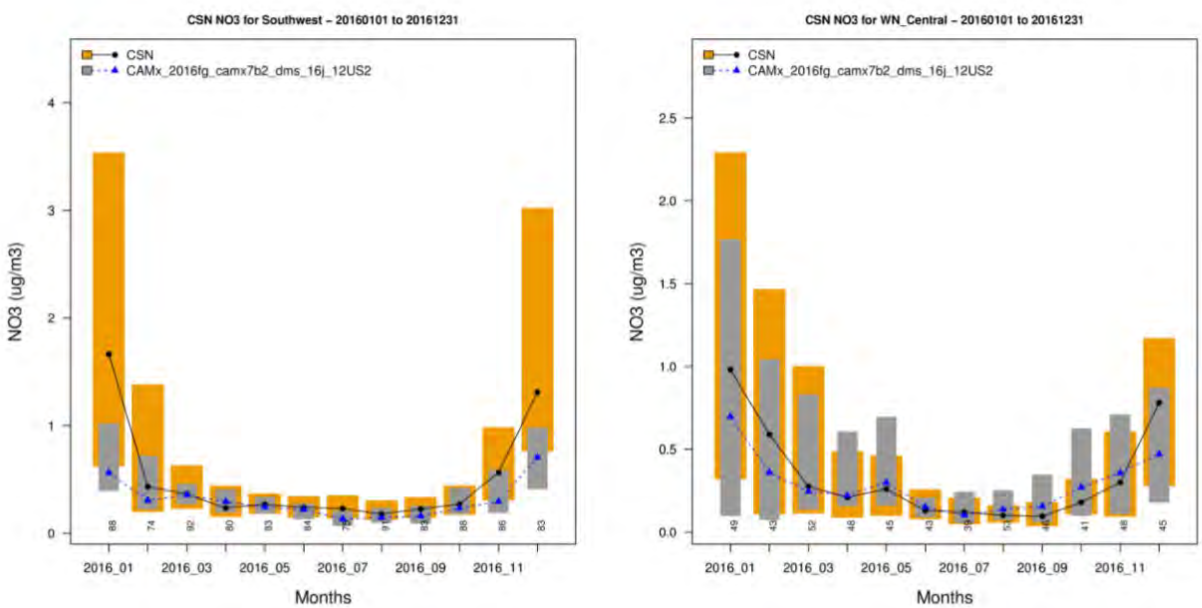
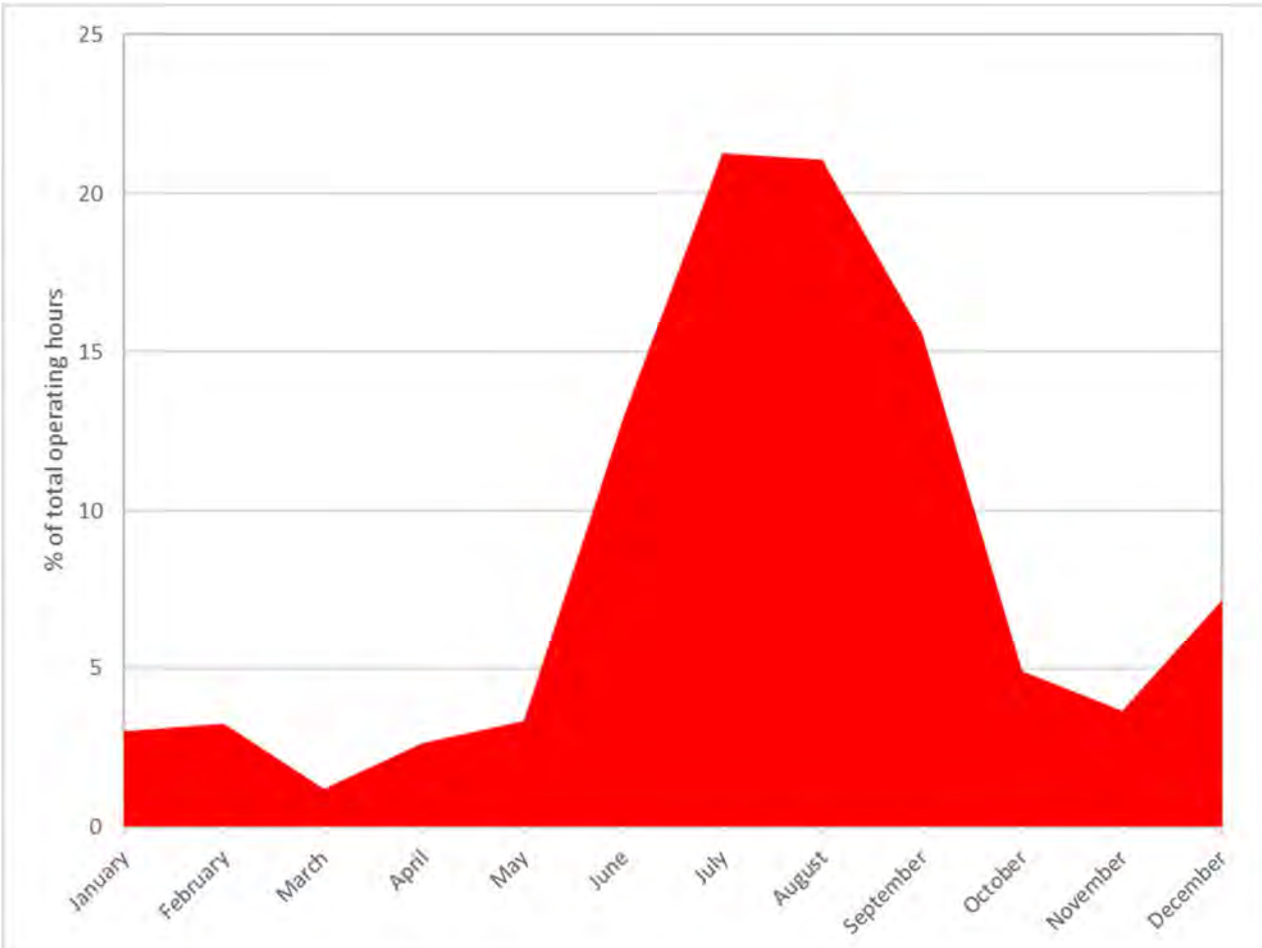


Figure A-3: Monthly Variation in North Valmy Operating Hours 2016 – 2018 Baseline Period



Glidepath Status for Jarbidge Wilderness Area

Figure A-4 shows the EPA modeling report[8] (for 2028 progress) glidepath status for Jarbidge Wilderness Area from Appendix B of the EPA document. It is evident that the "US anthro" portion of haze by 2028 in this area is a very small fraction, and that the EGU contribution to that small component is only 6%. Therefore, any further emission controls on Nevada EGUs are expected to have a minimal benefit on visibility. The adjusted glidepath indicates that the 2016 conditions have already attained the 2028 goal. Therefore, even if no additional controls on "US anthro" sources were requested, the modeling already indicates that the 2028 Reasonable Progress goal for Jarbidge is met.

[8] https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf

Figure A-4: EPA's September 2019 Modeling Report Glidepath Results for Jarbidge

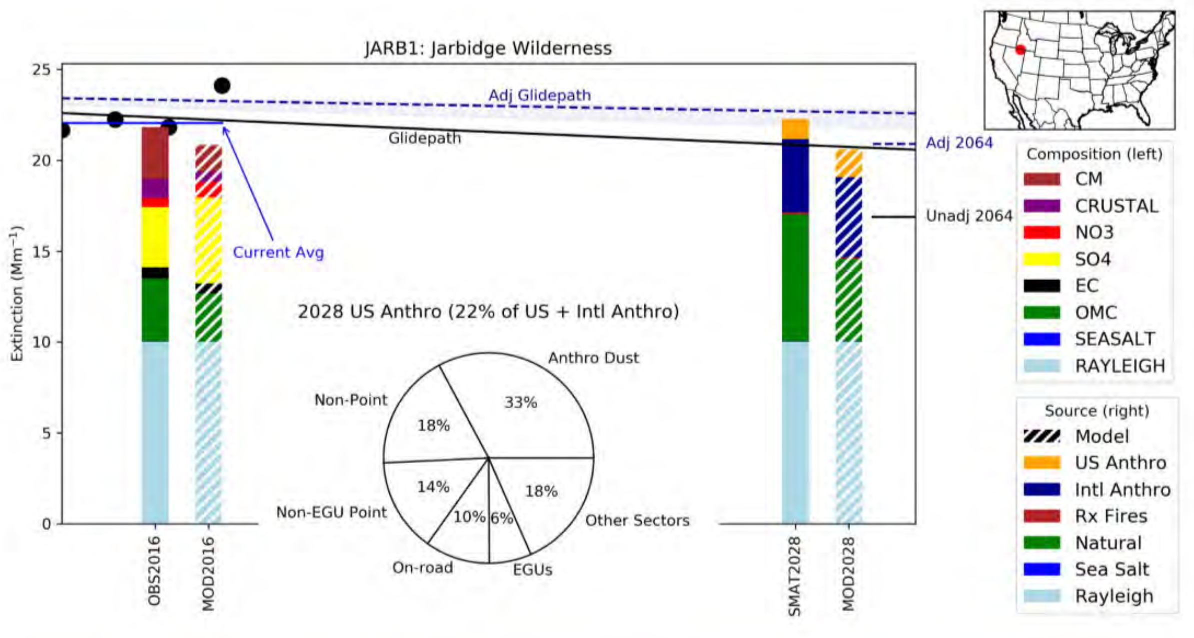


Figure 40: 2014-2017 IMPROVE observations, 2016 CAMx model predictions, 2028 modeled projection, and 2028 sector contributions at JARB1. Used for Class I areas: Jarbidge Wilderness.

Appendix B

Idaho Public Utilities Commission –

Approval of Idaho Power Company Application for Withdrawal from North Valmy Generating Station

Office of the Secretary
Service Date
May 31, 2019

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS RATES FOR ELECTRIC SERVICE TO RECOVER COSTS ASSOCIATED WITH THE NORTH VALMY POWER PLANT	**CASE NO. IPC-E-19-08** **ORDER NO. 34349**

On March 8, 2019, Idaho Power Company ("Idaho Power" or "Company") filed an Application requesting Commission approval of certain matters related to the Company's withdrawal from the North Valmy Generating Station ("Valmy").

On March 29, 2019, the Commission issued a Notice of Application and Notice of Modified Procedure establishing a May 10, 2019 comment deadline and a May 17, 2019 reply comment deadline. Order No. 34293. The Idaho Conservation League ("ICL") intervened as a party, and the ICL, Commission Staff, and several members of the public filed comments about the Application. The Company then filed a reply.

Now, based on our review of the record, the Commission approves the Application.

BACKGROUND

Valmy is a coal-fired power plant near Winnemucca, Nevada, consisting of two units. Unit 1 went into service in 1981 and Unit 2 in 1985. Idaho Power and NV Energy each own 50% of the plant, and NV Energy operates the plant. In IPC-E-16-24, the Commission approved a settlement stipulation ("Settlement Stipulation") under which the Company agreed to (1) negotiate with NV Energy to permanently end coal-burning operations at Valmy Unit 1 by December 31, 2019, and Valmy Unit 2 by December 31, 2025, or alternatively, (2) use prudent and commercially reasonable efforts to end its participation in Valmy along the same timeline. Order No. 33771 at 3. Also included in the Settlement Stipulation, as pertinent to this case, was the creation of a balancing account to track the incremental costs and benefits associated with the accelerated Valmy end-of-life date, a levelized revenue requirement that runs through 2028, and a commitment from the Company to analyze the economics of a Unit 2 retirement.

THE APPLICATION

The Company requests the Commission: (1) approve the North Valmy Project Framework Agreement between NV Energy and Idaho Power dated February 22, 2019

("Framework Agreement"); (2) find all actual Valmy investments through December 31, 2018 were prudently incurred; (3) allow investments at Valmy forecasted through December 31, 2025 to be included in the levelized revenue requirement mechanism established by Order No. 33771; and (4) adjust customer rates to recover the associated incremental annual levelized revenue requirement of $1.21 million, which equates to an overall increase of 0.11 percent, effective June 1, 2019. Application at 1-2. The Company estimates its requests would save customers about $17.2 million when compared to the costs they would pay if the Company were to operate both units through 2025 under current agreements. Errata to Application at 2.

COMMENTS

Commission Staff, ICL, and several customers filed comments about the Application, and the Company filed a reply. The comments and reply are summarized below.

A. Commission Staff.

Staff recommended the Commission approve the Company's requests. *See* Staff Comments at 11. Staff also recommended the Commission require the Company to: (1) file an analysis validating the December 31, 2025 Unit 2 closure date within 21 days of the Commission's Order, or provide a revised economic closing date within that same timeframe; (2) submit a filing by no later than February 15, 2022 that will true-up all prudently incurred actual costs through December 31, 2021, provide an update of forecasted investments including decommissioning costs, and validate the Unit 2 retirement date with an analysis conducted in the 2021 IRP, with rates to become effective June 1, 2022; (3) file an annual report detailing the amounts booked to the Valmy balancing account, similar to the requirement approved by the Commission for early closure of the Company's Boardman facility; and (4) work with Staff to develop documentation for audit and prudence review. *Id.* 11-12.

B. Idaho Conservation League.

ICL recommended the Commission approve the Framework Agreement. ICL notes that the exiting participant's capacity is not available for use by the remaining participant, which ensures air pollution will decrease upon exit and that the remaining participant will operate the plant so as not to increase common costs and remediation obligations after a participant's exit. This, in turn, will keep costs down. ICL believes the Framework Agreement sets reasonable exit fees, and establishes a reasonable process for evaluating, approving, and auditing actual costs incurred to decommission the plant.

ICL recommends the Commission defer any rate increase related to future spending on Unit 2 until the Company completes its 2019 IRP and submits a Unit 2 closure validation study. ICL notes that, in the Settlement Agreement approved in Case No. IPC-E-16-14, the Company agreed not to apply to change base rates in 2019 until it had completed a closure validation study, either as a stand-alone study or as part of its IRP, to examine the least cost/least risk closure date of Valmy units. Since the Company did neither of these things, ICL recommends the Commission defer judgment on the prudence of post-2019 Unit 2 operations until the Company completes its full 2019 IRP analysis and files the results.

C. Public Comments.

The Commission received two public comments on this matter. Both were opposed to the increase in rates.

D. Reply Comments of Idaho Power.

In its reply comments the Company agreed with Staff's recommendations that the Company file annual reports detailing amounts recorded in the Valmy balancing account, and submit a filing to true-up the balancing account with rates effective June 1, 2022. The Company also explained the process it used to evaluate a Unit 2 economic closure date.

Regarding the annual reports, the Company states it will work with Staff to develop the report and discuss available documentation. Regarding the true-up of forecasted-to-actual investments with rates effective June 1, 2022, the Company requested a due date of this filing of February 28, 2022 instead of February 15, 2022, in order to better align with its other auditing and reporting timelines. Regarding the analysis of its Unit 2 economic retirement date, the Company notes that a 21 day timeline will coincide and conflict with the Company finalizing its 2019 IRP due for filing on June 28, 2019. Therefore, the Company requests the Commission direct Idaho Power to make best efforts to file the application within 21 days. Regarding ICL's recommendation to defer a rate adjustment until after the Company completes its validation study of a Unit 2 withdrawal, the Company states that the balancing account and the studies completed to date give adequate assurance that customers will not be harmed.

COMMISSION FINDINGS AND DECISION

The Commission has jurisdiction over this matter under *Idaho Code* §§ 61-502 and 61-503. The Commission is empowered to investigate rates, charges, rules, regulations, practices, and contracts of public utilities and to determine whether they are just, reasonable, preferential, discriminatory, or in violation of any provision of law, and to fix the same by order. *Idaho Code* §§ 61-502 and 61-503. The Commission may enter any final order consistent with its authority under Title 61.

The Commission has reviewed the record, including the Application, the comments of Commission Staff, ICL, the public, and the reply comments of Idaho Power. Based on our review, we find it reasonable to: (1) approve the Framework Agreement; (2) deem all actual Valmy investments through December 31, 2018 were prudently incurred; (3) allow investments at Valmy forecasted through December 31, 2025 to be included in the levelized revenue requirement mechanism established by Order No. 33771; (4) adjust customer rates to recover the associated incremental annual levelized revenue requirement of $1.21 million, effective June 1, 2019; (5) direct the Company to use best efforts to file an analysis validating the December 31, 2025 economic retirement date of Unit 2 within 21 days of the service date of this Order; (6) require the Company to submit a filing by no later than February 28, 2022 to true-up the balancing account with forecast-to-actuals, with rates to become effective June 1, 2022; (7) require the Company to file an annual report detailing the amounts booked to the Valmy balancing account, similar to the requirement established in Order No. 32457 for the Company regarding early closure of the Boardman power plant; and (8) direct the Company to work with Staff to identify documentation for audit and prudence review.

We find the additional requirements proposed by Staff will help ensure that the Company's decisions are robustly analyzed and soundly justified, and that the costs incurred in continuing to operate and decommission Valmy will be prudent and correctly booked. While we recognize that costs to customers will increase slightly in the near term because of the Company's earlier than initially expected withdrawal from Valmy, we find that the Company's withdrawal from Valmy is ultimately in the public interest.

ORDER

IT IS HEREBY ORDERED that the Company's Framework Agreement with NV Energy is approved as prudent and commercially reasonable.

IT IS FURTHER ORDERED that all actual Valmy investments through December 31, 2018 are approved as prudently incurred.

IT IS FURTHER ORDERED that all forecasted investments at Valmy through December 31, 2025 are to be included in the levelized revenue requirement mechanism established by Order No. 33771.

IT IS FURTHER ORDERED that customer rates be adjusted to recover the incremental annual levelized revenue requirement of $1.21 million, effective June 1, 2019.

IT IS FURTHER ORDERED that the Company use best efforts to file, within 21 days of the service date of this Order; (1) an analysis validating the December 31, 2025 economic retirement date of Unit 2; or (2) an analysis supporting a different economic retirement date of Unit 2.

IT IS FURTHER ORDERED that the Company submit a filing by no later than February 28, 2022 to true-up the balancing account with forecast-to-actuals, with rates to become effective June 1, 2022.

IT IS FURTHER ORDERED that the Company file an annual report detailing the amounts booked to the Valmy balancing account.

IT IS FURTHER ORDERED that the Company work with Staff to identify documentation for audit and prudence review.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

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DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 30th day of May 2019.

PAUL KJELLANDER, PRESIDENT

KRISTINE RAPER, COMMISSIONER

ERIC ANDERSON, COMMISSIONER

ATTEST:

Diane M. Hanian
Commission Secretary

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Appendix C

Potential Emission Control Options –

Capital and Annual Cost Estimates for 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? Coal

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? 10,557 Btu/lb

What is the estimated actual annual MWh output? 313,221 MWh net

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10.175 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: Bituminous

Enter the sulfur content (%S) = 0.45 percent by weight

or

Select the appropriate SO_2 emission rate: < 3lb/MMBtu

Ash content (%Ash): 8.81 percent by weight

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	0.3368	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.2526	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.02	
	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	20	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	2019			
CEPCI for 2019	609.7	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	7	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) ($Cost_{ash}$)	48.80	\$/ton*		

CEPCI = Chemical Engineering Plant Cost Index Jun-19

* 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 ($/kWh)	2.4	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Fuel Cost ($/MMBtu)	1.89	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)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the 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/.	
Percent sulfur content for Coal (% weight)	9.23	Average ash content based on U.S. coal data for 2016 compiled by the 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/.	
Percent ash content for Coal (% weight)	11841.00	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/.	
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 =	2,414	MMBtu/hour
Maximum Annual MWh Output =	Bmw x 8760 =	2,078,166	MWh net
Estimated Actual Annual MWh Output (Boutput) =		313,221	MWh net
Heat Rate Factor (HRF) =	NPHR/10 =	1.02	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.151	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	1320	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	25	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	203.25	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	134.18	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)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	< 3	lbs/MMBtu
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)	307	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	1,615	lb/hour
	$(m_{sol} \times 7.4805)$/Reagent Density =	208.3	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day)/Reagent Density =	70,000	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	0.0944

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR$ =	38.3	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol}$/Density of water) $\times ((C_{stored}/C_{inj}) - 1)$ =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1)$ =	1.18	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1x10^6)/HHV$ =	9.8	lb/hour

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 ($SNCR_{cost}$) =	$2,918,292	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$4,142,661	in 2019 dollars
Total Capital Investment (TCI) =	$9,179,239	in 2019 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 ($SNCR_{cost}$) =	$2,918,292	in 2019 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 2019 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}) =	$4,142,661	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$405,630	in 2019 dollars
Indirect Annual Costs (IDAC) =	$870,651	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,276,281	in 2019 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 =	$137,689 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$261,234 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$3,812 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$2,580 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$316 in 2019 dollars
Direct Annual Cost =		$405,630 in 2019 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$4,131 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$866,520 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$870,651 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,276,281 per year in 2019 dollars
NOx Removed =	134 tons/year
Cost Effectiveness =	$9,512 per ton of NOx removed in 2019 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? Coal

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. 1.30

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

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?	10,557	Btu/lb
What is the estimated actual annual MWhs output?	313,221	MWh net
Enter the net plant heat input rate (NPHR)	10.175	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

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous

Enter the sulfur content (%S) = 0.45 percent by weight

For units burning coal blends:

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	0.3368	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0700	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	20	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 temperature, if known.

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	2019			
CEPCI for 2019	609.7	Enter the CEPCI value for 2019	609.7	2016 CEPCI
Annual Interest Rate (i)	7.0	Percent		
Reagent ($Cost_{reag}$)	0.950	$/gallon for 19% ammonia		
Electricity ($Cost_{elect}$)	0.0754	$/kWh		
Catalyst cost ($CC_{replace}$)	227.00	$/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 — Jun-19

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* 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 https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the 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/.		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	11,841	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/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/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 =	2,414	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	2,078,102	MWh net
Estimated Actual Annual MWhs Output (Boutput) =		313,221	MWh net
Heat Rate Factor (HRF) =	NPHR/10 =	1.02	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.151	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	1320	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	79.2	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	644.01	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	425.16	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.99	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	1,117,926	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	115.59	/hour
Residence Time	1/V_{space}	0.52	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 =	< 3	lbs/MMBtu
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	1.30	

* 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	0.3111	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})	9,671.06	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	1,165	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 $A_{catalyst}$	1,339	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	36.6	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	52	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 58 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in}$ x Q_B x EF x SRF x $MW_R)/MW_{NOx}$ =	250	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,317	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	170	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	57,100	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	0.0944

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	1338.42	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$73,645,202	in 2019 dollars
Reagent Preparation Cost (RPC) =	$3,693,567	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$8,104,795	in 2019 dollars
Total Capital Investment (TCI) =	$111,076,633	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$73,645,202	in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$3,693,567	in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 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 (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$8,104,795	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,656,812	in 2019 dollars
Indirect Annual Costs (IDAC) =	$10,495,512	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$12,152,324	in 2019 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 =	$555,383	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$213,112	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$133,246	in 2019 dollars
Annual Catalyst Replacement Cost =		$755,071	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.	
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$1,656,812	in 2019 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) =	$9,878	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$10,485,634	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$10,495,512	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$12,152,324	per year in 2019 dollars
NOx Removed =	425	tons/year
Cost Effectiveness =	$28,583	per ton of NOx removed in 2019 dollars

NV Energy - North Valmy Unit 1
Estimated Limestone Flue Gas Desulfurization System Cost

Input data

Escalation Indexes		2009	2019
Plant Cost (1)		521.9	609.7
Labor (2)		111.3	136.2
Raw Materials (3)		255.0	277.2
Annualization Data			
Equipment Life	20	years	
Interest Rate	7	%	
Capital Recovery Factor	0.0944		
Full Load Output	237	net MW	
Heat rate	10.175	MMBtu/net MW	
Projected Output (2028)	313,221.4	MWhr	
	15.1%	of full capacity	
Projected Heat Input (2028)	3,187,028	MMBtu/yr	
Proj. Uncontrolled SO2 Emisions (2028)	1,210.4	ton/yr	
	0.7596	lb/MMBtu	
FGD Removal Efficiency	96.6	%	
Controlled SO2 Projected Emissions (2028)	41.2	ton/yr	
Projected SO2 Removal (2028)	1,169.2	ton/yr	
Reagent Stoichiometric Ratio	1.03		
Reagent requirement (2028)	1,881.7	ton/yr	
Reagent cost, 2009	50	$/ton	
Reagent cost, 2028	54	$/ton	
Waste produced	3.31	ton/ton SO2 removed	
	3,873.5	ton waste/yr	
Waste disposal cost	10	$/ton	
Auxiliary power requirement at full load	5,214.0	kW	
Aux power requirement at 2028 load	786.6	kW	
	6,890.9	MWhr/yr	
Auxiliary power cost	50	$/MWhr	
Water requirement at full load	498,240	gal/day	
Water requirement at 2028 load	75,169	gal/day	
	27,437	1000 gal/yr	
Water cost	0.4	$/1000 gal	

Notes:
1 - Chemical Engineering Plant Cost Index (1957 - 1959 = 100)
2 - Bureau of Labor Statistics Employment Cost Index - Construction Labor (2005 = 100)
3 - Bureau of Labor Statistics Producer Price Index - Basic Inorganic Chemicals

Cost Estimate - Limestone FGD System

	S&L Study (2009 $)				Current Estimate (2019 $)			
	Equipment	Material	Labor	Total	Equipment	Material	Labor	Total
DIRECT COSTS								
Site Work	$75,000	$7,510,700	$6,459,700	$14,045,400	$87,600	$8,774,200	$7,904,900	$16,766,700
Limestone Handling System	$3,544,400	$966,400	$2,480,300	$6,991,100	$4,140,700	$1,129,000	$3,035,200	$8,304,900
FGD System - OEM Scope of Supply	$27,500,000	$619,300	$17,442,700	$45,562,000	$32,126,400	$723,500	$21,345,000	$54,194,900
Reagent Preparation	$0	$2,401,600	$5,420,400	$7,822,000	$0	$2,805,600	$6,633,100	$9,438,700
Absorber System	$621,000	$2,817,100	$3,787,200	$7,225,300	$725,500	$3,291,000	$4,634,500	$8,651,000
Dewatering System	$0	$1,655,600	$2,100,600	$3,756,200	$0	$1,934,100	$2,570,500	$4,504,600
Gypsum Handling & Loadout System	$985,000	$42,800	$401,100	$1,428,900	$1,150,700	$50,000	$490,800	$1,691,500
Demolition	$0	$125,000	$220,600	$345,600	$0	$146,000	$270,000	$416,000
Flue Gas System	$105,000	$1,422,300	$2,376,200	$3,903,500	$122,700	$1,661,600	$2,907,800	$4,692,100
Chimney	$20,000	$6,785,000	$10,438,000	$17,243,000	$23,400	$7,926,500	$12,773,200	$20,723,100
Wastewater treatment	$8,000	$61,200	$58,900	$128,100	$9,300	$71,500	$72,100	$152,900
Piping and Misc Equipment	$300,000	$1,290,300	$2,018,000	$3,608,300	$350,500	$1,507,400	$2,469,500	$4,327,400
Fire Protection, Detection & Alarm	$0	$785,000	$1,172,400	$1,957,400	$0	$917,100	$1,434,700	$2,351,800
Control & Instrumentation	$2,395,800	$70,100	$678,200	$3,144,100	$2,798,800	$81,900	$829,900	$3,710,600
Electrical	$2,052,500	$493,600	$1,377,000	$3,923,100	$2,397,800	$576,600	$1,685,100	$4,659,500
Scaffolding	$0	$500,000	$473,400	$973,400	$0	$584,100	$579,300	$1,163,400
Construction Equipment Supplement	$0	$1,200,000	$485,000	$1,685,000	$0	$1,401,900	$593,500	$1,995,400
SUBTOTAL - DIRECT COSTS	$37,606,700	$28,746,000	$57,389,700	$123,742,400	$43,933,400	$33,582,000	$70,229,100	$147,744,500
INDIRECT COSTS								
Construction Indirect Cost	$188,000	$5,892,900	$28,895,100	$34,976,000	$219,600	$6,884,300	$35,359,500	$42,463,400
Total Direct and Construction Indirect (D&CI)	$37,794,700	$34,638,900	$86,284,800	$158,718,400	$44,153,000	$40,466,300	$105,588,600	$190,207,900
Engineering, Procurement & Project Services		7% of D&CI		$11,110,300				$13,314,600
Construction Management/Field Engineering		2% of D&CI		$3,174,400				$3,804,200
Startup and Commissioning		1% of D&CI		$1,587,200				$1,902,100
Owner's Cost		3% of D&CI + other indirects		$5,237,700				$6,276,900
SUBTOTAL - INDIRECT COSTS				$56,085,600				$67,761,200
CONTINGENCY		15% of Direct and Indirect Costs		$26,974,200				$32,325,900
TOTAL CAPITAL COST				$206,802,200				$247,831,600
ANNUALIZED CAPITAL, OPERATING AND MAINTENANCE COST								
Annualized Capital Cost								$23,395,300
Variable O&M Cost								
FGD Disposal Cost								$38,700
Limestone Reagent Cost								$101,600
Auxiliary Power Cost								$344,500
Water Cost								$11,000
Total								$495,800
Fixed O&M Cost								
Operating Labor		12 operators @$45/hr, 40 hrs/wk						$1,123,200
Maintenance Materials		Per S&L study						$1,132,000
Mantainance Labor		Per S&L study						$755,000
Total								$3,010,200
TOTAL ANNUALIZED CAPITAL, OPERATING AND MAINTENANCE COST								$26,901,300
Cost Effectiveness ($/ton controlled)								$23,008

NV Energy - North Valmy Unit 1
Estimated Lime Flue Gas Desulfurization System Cost

Input data

Escalation Indexes		2009	2019
Plant Cost (1)		521.9	609.7
Labor (2)		111.3	136.2
Raw Materials (3)		255.0	277.2
Annualization Data			
Equipment Life		20	years
Interest Rate		7	%
Capital Recovery Factor		0.0944	
Full Load Output		237	net MW
Heat rate		10.175	MMBtu/net MW
Projected Output (2028)		313,221.4	MWhr
		15.1%	of full capacity
Projected Heat Input (2028)		3,187,028	MMBtu/yr
Proj. Uncontrolled SO2 Emisions (2028)		1,210.4	ton/yr
		0.7596	lb/MMBtu
FGD Removal Efficiency		96.6	%
Controlled SO2 Projected Emissions (2028)		41.2	ton/yr
Projected SO2 Removal (2028)		1,169.2	ton/yr
Reagent Stoichiometric Ratio		1.03	
Reagent requirement (2028)		1,392.5	ton/yr
Reagent cost, 2009		150	$/ton
Reagent cost, 2028		163	$/ton
Waste produced		3.41	ton/ton SO2 removed
		3,986.4	ton waste/yr
Waste disposal cost		10	$/ton
Auxiliary power requirement at full load		4,740.0	kW
Aux power requirement at 2028 load		715.1	kW
		6,264.4	MWhr/yr
Auxiliary power cost		50	$/MWhr
Water requirement at full load		433,440	gal/day
Water requirement at 2028 load		65,393	gal/day
		23,868	1000 gal/yr
Water cost		0.4	$/1000 gal

Notes:
1 - Chemical Engineering Plant Cost Index (1957 - 1959 = 100)
2 - Bureau of Labor Statistics Employment Cost Index - Construction Labor (2005 = 100)
3 - Bureau of Labor Statistics Producer Price Index - Basic Inorganic Chemicals

Cost Estimate - Lime FGD System

	S&L Study (2009 $)				Current Estimate (2019 $)			
	Equipment	Material	Labor	Total	Equipment	Material	Labor	Total
DIRECT COSTS								
Site Work	$75,000	$7,309,100	$6,373,100	$13,757,200	$87,600	$8,538,700	$7,798,900	$16,425,200
Lime Handling System	$235,000	$1,496,600	$1,937,200	$3,668,800	$274,500	$1,748,400	$2,370,600	$4,393,500
FGD System - OEM Scope of Supply	$26,500,000	$619,300	$17,442,700	$44,562,000	$30,958,100	$723,500	$21,345,000	$53,026,600
Reagent Preparation	$0	$2,401,600	$5,109,500	$7,511,100	$0	$2,805,600	$6,252,600	$9,058,200
Absorber System	$621,000	$2,817,100	$3,787,200	$7,225,300	$725,500	$3,291,000	$4,634,500	$8,651,000
Dewatering System	$0	$1,655,600	$2,100,600	$3,756,200	$0	$1,934,100	$2,570,500	$4,504,600
Gypsum Handling & Loadout System	$985,000	$42,800	$401,100	$1,428,900	$1,150,700	$50,000	$490,800	$1,691,500
Demolition	$0	$125,000	$220,600	$345,600	$0	$146,000	$270,000	$416,000
Flue Gas System	$105,000	$1,422,300	$2,376,200	$3,903,500	$122,700	$1,661,600	$2,907,800	$4,692,100
Chimney	$20,000	$6,785,000	$10,438,000	$17,243,000	$23,400	$7,926,500	$12,773,200	$20,723,100
Wastewater treatment	$8,000	$61,200	$58,900	$128,100	$9,300	$71,500	$72,100	$152,900
Piping and Misc Equipment	$300,000	$1,290,300	$2,018,000	$3,608,300	$350,500	$1,507,400	$2,469,500	$4,327,400
Fire Protection, Detection & Alarm	$0	$560,000	$891,600	$1,451,600	$0	$654,200	$1,091,100	$1,745,300
Control & Instrumentation	$2,275,800	$70,100	$652,600	$2,998,500	$2,658,700	$81,900	$798,600	$3,539,200
Electrical	$2,052,500	$493,600	$1,377,000	$3,923,100	$2,397,800	$576,600	$1,685,100	$4,659,500
Scaffolding	$0	$500,000	$473,400	$973,400	$0	$584,100	$579,300	$1,163,400
Construction Equipment Supplement	$0	$1,200,000	$485,000	$1,685,000	$0	$1,401,900	$593,500	$1,995,400
SUBTOTAL - DIRECT COSTS	$33,177,300	$28,849,600	$56,142,700	$118,169,600	$38,758,800	$33,703,000	$68,703,100	$141,164,900
INDIRECT COSTS								
Construction Indirect Cost	$165,900	$5,914,200	$28,262,300	$34,342,400	$193,800	$6,909,200	$34,585,100	$41,688,100
Total Direct and Construction Indirect (D&CI)	$33,343,200	$34,763,800	$84,405,000	$152,512,000	$38,952,600	$40,612,200	$103,288,200	$182,853,000
Engineering, Procurement & Project Services		7% of D&CI		$10,675,800				$12,799,700
Construction Management/Field Engineering		2% of D&CI		$3,050,200				$3,657,100
Startup and Commissioning		1% of D&CI		$1,525,100				$1,828,500
Owner's Cost		3% of D&CI + other indirects		$5,032,900				$6,034,100
SUBTOTAL - INDIRECT COSTS				$54,626,400				$66,007,500
CONTINGENCY		15% of Direct and Indirect Costs		$25,919,400				$31,075,900
TOTAL CAPITAL COST				$198,715,400				$238,248,300
ANNUALIZED CAPITAL, OPERATING AND MAINTENANCE COST								
Annualized Capital Cost								$22,490,600
Variable O&M Cost								
FGD Disposal Cost								$39,900
Lime Reagent Cost								$227,000
Auxiliary Power Cost								$313,200
Water Cost								$9,500
Total								$589,600
Fixed O&M Cost								
Operating Labor		12 operators @$45/hr, 40 hrs/wk						$1,123,200
Maintenance Materials		Per S&L study						$1,088,000
Mantainance Labor		Per S&L study						$726,000
Total								$2,937,200
TOTAL ANNUALIZED CAPITAL, OPERATING AND MAINTENANCE COST								$26,017,400
Cost Effectiveness ($/ton controlled)								$22,252

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? Coal

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)? 264 MW net

What is the higher heating value (HHV) of the fuel? 10,557 Btu/lb

What is the estimated actual annual MWh output? 378,442 MWh net

Is the boiler a fluid-bed boiler? No

Enter the net plant heat input rate (NPHR) 10.949 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: Bituminous

Enter the sulfur content (%S) = 0.45 percent by weight

or

Select the appropriate SO_2 emission rate: < 3lb/MMBtu

Ash content (%Ash): 8.81 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	0	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days	Plant Elevation	4455 Feet above sea level
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.3168	lb/MMBtu		
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.2376	lb/MMBtu		
Estimated Normalized Stoichiometric Ratio (NSR)	1.05			
	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	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	2019			
CEPCI for 2019	609.7	Enter the CEPCI value for 2019	541.7	2016 CEPCI
Annual Interest Rate (i)	7	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}$)	48.80	$/ton*		

CEPCI = Chemical Engineering Plant Cost Index

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* 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 Mo	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 ($/kWh)	2.4	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Fuel Cost ($/MMBtu)	1.89	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)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the 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/.	
Percent sulfur content for Coal (% weight)	9.23	Average ash content based on U.S. coal data for 2016 compiled by the 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/.	
Percent ash content for Coal (% weight)	11841.00	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/.	
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 =	2,891	MMBtu/hour
Maximum Annual MWh Output =	Bmw x 8760 =	2,313,076	MWh net
Estimated Actual Annual MWh Output (Boutput) =		378,442	MWh net
Heat Rate Factor (HRF) =	NPHR/10 =	1.09	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.164	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	1433	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	25	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	228.96	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	164.08	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)	1.00	
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	< 3	lbs/MMBtu
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)	357	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	1,878	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	242.2	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	81,400	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	0.0944

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	41.4	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) =	1.37	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	11.4	lb/hour

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 ($SNCR_{cost}$) =	$3,148,048	in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0	in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	$4,353,464	in 2019 dollars
Total Capital Investment (TCI) =	$9,751,966	in 2019 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 ($SNCR_{cost}$) =	$3,148,048	in 2019 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 2019 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}) =	$4,353,464 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$484,148 in 2019 dollars
Indirect Annual Costs (IDAC) =	$924,974 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$1,409,122 in 2019 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 =	$146,279	in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$329,741	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$4,471	in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$3,257	in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$399	in 2019 dollars
Direct Annual Cost =		$484,148	in 2019 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$4,388	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$920,586	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$924,974	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$1,409,122	per year in 2019 dollars
NOx Removed =	164	tons/year
Cost Effectiveness =	$8,588	per ton of NOx removed in 2019 dollars

Data Inputs

SCR Cost Estimate - North Valmy Unit 2

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Coal

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. 1.30

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

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? 10,557 Btu/lb

What is the estimated actual annual MWhs output? 378,442 MWh net

Enter the net plant heat input rate (NPHR) 10.949 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

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous

Enter the sulfur content (%S) = 0.45 percent by weight

For units burning coal blends:

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	0.3168	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0700	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	20	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 actual temperature, if known.

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	2019			
CEPCI for 2019	609.7	Enter the CEPCI value for 2019	609.7	2016 CEPCI
Annual Interest Rate (i)	7.0	Percent		
Reagent ($Cost_{reag}$)	0.950	$/gallon for 19% ammonia		
Electricity ($Cost_{elect}$)	0.0754	$/kWh		
Catalyst cost ($CC_{replace}$)	227.00	$/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 Jun-19

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* 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 https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the 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/.		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	11,841	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/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/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 =	2,891	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	2,313,076	MWh net
Estimated Actual Annual MWhs Output (Boutput) =		378,442	MWh net
Heat Rate Factor (HRF) =	NPHR/10 =	1.09	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.164	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	1433	hours
NOx Removal Efficiency (EF) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	77.9	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	713.46	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	511.27	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.97	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	1,339,030	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	117.83	/hour
Residence Time	$1/V_{space}$	0.51	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 =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu
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	1.30	

* 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	0.3111	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})	11,364.03	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	1,395	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 $A_{catalyst}$	1,604	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	40.1	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	52	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 $MW_R)/MW_{NOx}$ =	277	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,459	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	195	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	65,600	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	0.0944

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	1537.49	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$86,655,837	in 2019 dollars
Reagent Preparation Cost (RPC) =	$3,789,348	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$8,742,998	in 2019 dollars
Total Capital Investment (TCI) =	$128,944,639	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$86,655,837 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$3,789,348 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 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 (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$8,742,998 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,906,822	in 2019 dollars
Indirect Annual Costs (IDAC) =	$12,183,324	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$14,090,146	in 2019 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 =	$644,723	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$265,428	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$166,149	in 2019 dollars
Annual Catalyst Replacement Cost =		$830,522	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.	
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$1,906,822	in 2019 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) =	$10,950	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$12,172,374	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$12,183,324	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$14,090,146	per year in 2019 dollars
NOx Removed =	511	tons/year
Cost Effectiveness =	$27,559	per ton of NOx removed in 2019 dollars

Year to be CLosed	Remaining Life	Cost effectiveness	Capital Recovery, % ot total annual cost	Captial Recovery, $/yr
		$/ton controlled		
		$27,559	86.39%	$12,172,374
2030	2	$143,245	97.38%	$71,319,280
2035	7	$50,560	92.58%	$23,932,125
2040	12	$35,503	89.43%	$16,234,130
2048	20	$27,559	86.39%	$12,172,374
2058	30	$24,079	84.42%	$10,392,938

Appendix B.5.c - Response Letter 1

July 8, 2020

Steven McNeece
Nevada Department of Environmental Protection
901 S. Stewart Street
Suite 4001
Reno, NV 89701

Re: Response to Request for Additional Information
Regional Haze 4 Factor Analyses
NV Energy Tracy (FIN 0029) and Valmy (FIN A0375) Generating Stations

Mr. McNeece:

Per your email correspondence dated May 28, 2020, Nevada Power Company d/b/a NV Energy (NVE) hereby provides the requested response detailing additional information regarding 4 Factor Analyses at both the Tracy and North Valmy Generating Stations previously submitted March 13, 2020. This letter and attachments address NDEP's several questions and should be considered an addendum to the previously submitted Four Factor Analyses.

NVE appreciates the opportunity to work with NDEP in this endeavor. Please feel free to contact Sean Spitzer at (702) 402-5132 should you have any questions.

Sincerely,

Starla Lacy

Starla Lacy
Vice President, Environmental Services, Safety, and Land Management
NV Energy

Tracy Generating Station

Response to 4 Factor Analysis Additional Information Request

Question (1)(a) **Unit 3 and 6: Interest Rate for Capital Recovery**

NDEP initially requested that NV Energy (NVE) recalculate the cost-effectiveness of pollution control options using an interest rate of 3.25% (equal to the current bank prime lending rate) rather than the higher interest rate that was used to annualize the capital cost of these options in NVE's previously submitted report. However, during a follow-up call with NDEP on 6/22/20, NVE explained that as a regulated utility, its cost of capital is determined differently than for an unregulated entity. NVE'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) and is not fairly represented by the current bank prime rate. The cost of capital for NVE's operating utilities consist of several components and are established triennially in a regulatory proceeding called a General Rate Case (GRC). In the most recent GRC, the PUCN established SPPC's cost of capital (i.e., its rate of return on capital investments) at 6.75%.

The attached amended cost-effectiveness tables use this 6.75% 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 Tracy) must separately go through a GRC filing and approval process with the PUCN every 3 years. 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, the PUCN-approved weighted average cost of capital is 6.75%. 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.

Question (1)(b) **Units 3 and 6: SCR Equipment Life.**

NDEP has requested that NVE use an equipment life of 30 years when annualizing the capital cost of installing Selective Catalytic Reduction (SCR) on both Units 3 and 6. NVE disagrees that a 30 year life assumption is appropriate for SCR in this instance, but in the attached tables has provided a cost-effectiveness calculation on that basis as requested. As explained below, NVE believes that NVE's original assumption of an equipment life of 20 years for SCR on these units is already a very conservative estimate, because it already significantly overstates the actual anticipated remaining life of these two generating units.

NVE Tracy units 3 and 6 were originally installed in 1974 and 1996, respectively. As such they are already 46 and 24 years old, respectively. Both these units are much less efficient than other NVE units and have planned retirement dates in 2028 for Unit 3 and 2031 for Unit 6-Pinon

Pine. These planned retirement dates have been communicated to the Public Utility Commission of Nevada in NVE's Life Span Analysis Process (LSAP) and represent NVE's best estimate, and commitment, on life expectancy. Assuming that the installation of SCR, if required, would occur in 2025, the SCR would only have a 3 - 6 year life before these generating units would be retired, if these planned retirement dates occur. Therefore, NVE's original economic analysis assumption of 20 years of emission control equipment life is already extremely conservative. To help NDEP understand the impact of different remaining useful life assumptions, NVE presents a sensitivity analysis showing 10, 20, and 30 year life cases in the attached revised cost-effectiveness tables.

Question (2) (a) Unit 3: SCR Days of Operation in EPA spreadsheet

NDEP observed that in using EPA's SCR cost spreadsheet to estimate the capital and annual costs for SCR for Unit 3, NVE entered a value of 92 days (2,199 hours) as the expected operating days per year. NDEP initially requested that NVE revise the calculation to assume 365 days of annual operation since the boiler is permitted to run year-round. However, in a call with NDEP on 6/22/20, NVE explained that the reason a lower number was used in the EPA spreadsheet was because this lower value matches the usage of this unit during the baseline period and avoids overestimating the SCR operating cost. Following our discussions, we understand that NDEP agrees that the 2,199 hr value is the appropriate basis for this cost-effectiveness calculation. This is further explained in the following paragraph.

The Four Factor analysis is intended to estimate the cost-effectiveness of possible controls relative to baseline actual emissions. For the Unit 3 boiler, SCR has the potential to reduce NOx emissions approximately 75.5 tons/yr NOx vs baseline actual emissions. To estimate the cost-effectiveness of SCR in this scenario, we need to calculate the capital and operating costs for this same scenario. The capital cost of SCR is based on the size of the unit and not affected by its projected operating hours. However, the operating hours input into the EPA SCR cost spreadsheet does affect annual operating costs such as the catalyst replacement cost, which is higher if one assumes more hours of operation. If NVE input 365 days of operation in the EPA spreadsheet, it would artificially inflate the actual operating cost, making SCR look even less cost-effective. Accordingly, NVE has not made any change to this parameter.

Question (3)(a) <u>Unit 6: Dry Low NOx Combustor Conversion Cost Calculation</u>

NVE's original cost-effectiveness analysis for retrofitting Unit 6 with DLN Combustor was based in part on the confidential cost estimate provided by GE. NDEP requested additional details of the cost estimate or justification of the confidentiality of the quote and its appropriateness for this analysis.

NVE discussed NDEP's request for additional details of the DLN combustor pricing information with GE. GE maintains that the details of that original cost quotation are business confidential, but has provided NVE with a separate non-confidential budgetary cost estimate. They have also provided NVE with additional perspective regarding the installation costs. With this new non-confidential information, NVE has updated our DLN combustor capital cost estimate which is attached and provides a detailed breakdown of the estimated costs. This updated capital cost estimate is within about 5% of our previous submittal.

As a separate issue, we'd like to highlight why the option to retrofit this turbine with a DLN combustor is very expensive, which may seem unexpected given that most new turbines come already equipped with DLN combustor to minimize NOx. There is a significant difference in the cost to use a DLN combustor on a new turbine versus the cost of a retrofit. The combustor system and fuel controls are major components of a turbine and a large portion of its cost. However, the extra cost to provide a DLN combustor on a new turbine is very small. Although you have to pay for the cost of the DLN combustor, you avoid the cost for a conventional combustor. The net cost difference is small and easily justified by the NOx benefit.

However, in this specific case, Pinon was installed with GE's Multi Nozzle Quiet Combustor (MNQC) because it was designed to burn a range of low heating value fuels including gasified coal. The total cost of that combustor are sunk costs and are no longer recoverable to help offset the cost of an entirely new DLN burner and its installation. Because the combustor system and fuel controls are major components of the turbine, their cost is very significant. In this case, the costs to remove the existing MNQC combustor system and replace it with a new DLN system is over $10 million capital and is actually more expensive than adding SCR (although SCR is also expensive).

Question (3)(a) (continued) <u>Unit 6: DLN Combustor Heat rate impacts and excess water costs</u>

NVE's cost analysis for a DLN Combustor mentioned, but did not quantify, that a DLN conversion would impact the turbine's output and heat rate and also result in treatment or disposal costs for the excess water resulting from discontinuing steam injection. NDEP requested additional information on these costs, if available. Even without these additional costs, a DLN conversion is extremely expensive. However, the following provides additional information about these additional impacts.

Heat Rate Impacts: A turbine's "heat rate" is the amount of fuel (MMBtu) necessary to generate a unit of electricity (KWH). Steam injection increases the mass flow through the turbine and helps increase a turbine's output and efficiency. Discontinuing steam injection will require an increase to the amount of turbine fuel needed to generate the same amount of electricity from the turbine. GE estimates that the turbine heat rate will increase 3.97% by conversion to a DLN combustor. However, this extra fuel use will partially be offset by not having to generate the steam used for the injection. NVE's original Four Factor analysis did not include this cost but did separately include an estimate of the related cost associated with just a derate of the turbine (less generation capacity at maximum load). NVE estimated the derate cost to be $870,000 (as documented in the original Four Factor Report). To respond to NDEP's request, NVE has taken a different approach to estimate the overall increased costs associated with all three influences: 1) the derate, 2) heat rate impacts, and 3) less fuel to generate steam. 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. This value is actually slightly less than NVE had previously estimated for the derate alone. This is primarily because NVE's original estimate assumed derate costs of purchasing capacity year round, but the new estimate is more conservatively based on the assumption that capacity purchases may only be required during the summer months. NVE believes this updated estimate is more accurate. For the attached updated cost tables, NVE has included this adjusted (lower) estimated annual operating expense.

Water Impacts: The DLN conversion would have a negative impact on the plant's water balance and result in a wastewater stream requiring treatment or disposal. Currently, the use of a steam injection system is integrated into the overall plant water balance by using existing process wastewater to produce demineralized water for use in the steam injection system. Converting this turbine to DLN would create a wastewater stream of 100 to 150 gpm, requiring additional investment for disposal. NVE is uncertain how this stream could be handled, and is therefore unable to estimate the costs associated with its impact on the facility. NVE anticipates the cost to add equipment to address this additional wastewater would require a multi-million dollar capital investment, but the exact order of magnitude is unknown. Because of the current uncertainty of the magnitude of these costs, NVE has not included any extra costs for this item in our DLN cost-effectiveness calculation. Nevertheless, given that the costs for this control option are already very high, the omission of these extra costs should not affect the result of the Four Factor Analysis.

Question (3)(b) <u>Unit 6: NV Energy Cost Estimates</u>

NDEP requested additional information on the basis of the non-vendor cost estimates listed under "Unit 6 Direct Installation Costs" and how they are consistent with the principles in the EPA Cost Control Manual.

The following discussion presents each of these direct installation cost estimates and provides a discussion of the basis of the cost estimate and how those costs are consistent with the principles in EPA's cost manual. The EPA Cost Control Manual does not provide equations to estimate the costs for SCR for a combustion turbine (it only addresses utility and industrial boilers). Instead, NVE obtained a vendor quote as the primary basis for the cost estimate. Items added to the vendor quotation and listed below are standard components of an SCR system design/installation and were not included in the vendor quotation. The below comments regarding EPA's Cost Control Manual, unless otherwise indicated, refer to Section 4 NOx Controls, Chapter 2 Selective Catalytic Reduction, version June 2019.

(i) Local Labor Rate Adjustment to Vendors Installation Cost Estimate: $92,500

Basis of Cost Estimate: This Installation cost adjustment is a 5% increase to the vendor provided installation cost estimate to account for higher labor rates in the Reno, NV area vs the national average. The installation cost estimate provided by the vendor was based on generic national rates. NVE's experience is that the average labor rates in the Reno area are higher than many other areas, and higher than the national average. To adjust for this difference, NVE used data from the US Bureau of Labor Statistics. For the labor category 472152 which includes pipefitter and steamfitters (typical labor for this type work), the national average in May 2018 was $29.96/hr. The Reno area average was $30.39/hr, which is 9% above the national average. However, NVE used a lower more conservative 5% adjustment.

Website for Labor Statistics:

https://data.bls.gov/oes/#/occGeo/One%20occupation%20for%20multiple%20geographical%20areas

Related principle in the EPA Cost Manual: The EPA Cost Manual does not provide cost estimating techniques for SCR for a combustion turbine. However, in Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology (section 2.6.5.2) the EPA manual states that wage rates vary widely, depending on geographical location, and other factors. The EPA manual states that wage data is tabulated and periodically updated by the U.S. Department of Labor, Bureau of Labor Statistics and in other publications. It states that the Cost Manual uses labor rates that are representative of industries at the national level, which is generally adequate for study level purposes. But EPA does not suggest it is inappropriate to include, if available, location specific labor data. In fact, EPA provides a reference to a source of geographic specific wage data (Dept. of Labor, Bureau of Labor Statistics) which is NVE's source. Additionally, EPA cost equations for utility and industrial SCR units include a 30% adjustment factor (multiplier of 1.3) intended to account for, among other things, "'labor adjustment for installation (e.g., per diem and premium for work shifts of 10 hr)". In EPA's Response to Comments for the Cost Manual update, EPA explains that this 1.3 factor includes an assumption of time-and-a-half for the extra 2 hrs of a 10 hr shift - which increases labor costs by 10% (vs 8 hr shift).

(ii) Heat tracing and insulation: $50,000

Basis of Cost Estimate: The vendor estimate of installation costs specifically states that heat tracing and insulation are to be provided by NVE. NVE's cost estimate is on the low end of estimates provided by NVE construction project managers based on historical experience at other NVE facilities, as well as their professional knowledge and perspective.

Related principal in the EPA Cost Manual: The EPA cost Manual SCR chapter states in 2.2.4: "The applicability of heat tracing, insulation, and seismic design criteria are determined based on site specific conditions."

(iii) Sampling grid: $150,000

Basis of Cost Estimate: This is NVE's estimate is to build scaffold and labor for installing a permanent grid for tuning and sampling. Installing a permanent sampling grid allows regular tuning of the SCR ammonia injection grid to maximize ammonia utilization, minimize operating and maintenance costs, minimize ammonia slip, and improve NOx performance. This cost estimate is based on costs for installing a sampling grid at an SCR installation at NVE's Silverhawk Generating Station near Las Vegas, NV.

Related principle in the EPA Cost Manual: The EPA Cost Manual makes several references to the ammonia injection grid as a critical component of an SCR system. It additionally specifies that "annual ammonia injection grid (AIG) tuning and optimization is also conducted to ensure uniform flow rate/velocity and uniform NH3/NOx molar distribution. " It does not itemize costs for a sampling grid to facilitate that routine testing, but it is NVE's standard practice to provide this for SCR systems.

(iv) Category: Ammonia Injection Grid Tuning: $100,000

Basis of Cost Estimate: The vendor SCR capital cost estimate did not include initial tuning. This cost estimate assumes 4 days of testing and valve adjustments. This estimate is informed by the tuning costs of the recently performed SCR tuning at the NVE Silverhawk Generating Station. Station Tuning requires stack testers for a few days to do the testing, tuning engineers to review the stack tester data, and operators to make the recommended ammonia valve adjustments. Tuning involves about two tests per day and two valve adjustments per day. At Silverhawk, NVE originally estimated needing 3 days including mobilization and demobilization. However, they actually needed eight days total covering two sets of testing. They also had testers perform ammonia grid testing for 2 days following their scheduled RATA testing. The assumption of 4 days and the above costs are reasonable if testing goes well, and is low if it doesn't.

Related principle in the EPA Cost Manual: The EPA Cost Manual indicates Ammonia Injection Grid Annual tuning typically costs $30K to $50K. It doesn't separately address first year/initial tuning costs, which are logically higher, and in practice have been higher based on NVE's recent project experience.

(v) Category: CFD modeling: $50,000

Basis of Cost Estimate: Computational Fluid Dynamic (CFD) modeling is recommended by the vendor but is not included in their estimate. These costs are estimated by NVE based on experience and includes one set of NOx tests (separate from tuning tests). Flue gas flow distribution and mixing of ammonia with flue gas have a significant impact on an SCR's performance. Modeling with computational fluid dynamics models is helpful to improve the design and system performance.

Related principle in the EPA Cost Manual: The EPA Cost Manual SCR section states that "Computational fluid dynamics and chemical kinetic modeling are performed as part of the design process for SCR" and "the design is highly site-specific. . . SCR system design is generally undertaken by . . . the SCR system supplier, who specifies the required catalyst volume and other design parameters based on prior experience and computational fluid dynamics and chemical kinetic modeling". These are part of the capital costs for SCR but were not included in the vendor quotation.

Question (3)(c) <u>Unit 6: Cost of Implementing Both SCR and DLN Conversion.</u>

NVE's original Four Factor Report showed the individual costs of implementing either DLN or SCR for the Unit 6 combustion turbine but did not explicitly show the cost of doing both. NDEP has requested a presentation of the cost effectiveness of implementing both SCR and DLN. NVE has included this control scenario in the attached updated cost tables. The cost to do both control options is roughly equal to the sum of the costs of the options individually (minus some reagent cost savings) but would only provide a very small incremental benefit versus implementing SCR alone. Thus, as shown in the attached tables, the incremental cost to add a DLN conversion on top of SCR is over $200,000/ton, which is clearly cost prohibitive.

ATTACHMENT A

Revised Cost Tables for Tracy Generating Station's 4 Factor Analysis

Attachment A

Revised Cost Tables for NV Energy Four Factor Analysis

Table 1 – Tracy Unit #3 NOx Control Option Cost-Effectiveness

Selective Non-Catalytic Reduction			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$4,208,000		
Annual Capital Recovery ($/yr)	$592,220	$389,521	$330,632
Annual Operating Cost (excl. capital recovery) ($/yr)	$85,120		
Total Annual Costs ($/yr)	$677,340	$474,641	$415,752
Annual Emission Rate with Controls (Tons/yr)	62.9 tons/yr		
NOx Emission Reduction (Tons/year)	21.0		
Control Cost Effectiveness ($/Ton)	**$32,254**	**$22,602**	**$19,798**

Capital and Annual Operating Cost are same as in original NVE Four Factor Report. Only change is 6.75% interest assumption and variable equipment life assumptions

Selective Catalytic Reduction (SCR)			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$15,564,000		
Annual Capital Recovery ($/yr)	$2,190,425	$1,440,708	$1,222,897
Annual Operating Cost (excl. capital recovery) ($/yr)	$164,143		
Total Annual Costs ($/yr)	$2,354,568	$1,604,851	$1,387,040
Annual Emission Rate with Controls (Tons/yr)	8.4 tons/yr		
NOx Emission Reduction (Tons/year)	75.5		
Control Cost Effectiveness ($/Ton)	**$31,186**	**$21,256**	**$18,371**

Capital and Annual Operating Cost are same as in original NVE Four Factor Report. Only change is 6.75% interest assumption and variable equipment life assumptions

Table 2 – Tracy Unit #6/Piñon Pine 4 - NOx Control Option Cost-Effectiveness

Dry Low NOx Combustor Conversion			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$13,464,516		
Annual Capital Recovery ($/yr)	$1,894,950	$1,246,366	$1,057,936
Annual Operating Cost (excl. capital recovery) ($/yr)	$680,000		
Total Annual Costs ($/yr)	$2,574,950	$1,926,366	$1,737,936
Annual Emission Rate with Controls (Tons/yr)	78 tons/yr		
NOx Emission Reduction (Tons/year)	135.0		
Control Cost Effectiveness ($/Ton)	**$19,074**	**$14,269**	**$12,874**

Capital Cost estimate is the same as in original NVE Four Factor Report. Changes are subtracting $214K to operating cost for updated heat rate/derate impacts, change interest rate to 6.75%, and show variable equipment life assumptions

Selective Catalytic Reduction w/existing steam injection			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$7,684,000		
Annual Capital Recovery ($/yr)	$1,081,420	$711,282	$603,748
Annual Operating Cost (excl. capital recovery) ($/yr)	$721,367		
Total Annual Costs ($/yr)	$1,802,787	$1,432,649	$1,325,115
Annual Emission Rate with Controls (Tons/yr)	21.3 tons/yr		
NOx Emission Reduction (Tons/year)	192.0		
Control Cost Effectiveness ($/Ton)	**$9,390**	**$7,462**	**$6,902**

Capital Cost estimate is the same as in original NVE Four Factor Report. Changes are adding $40K to operating cost for annual ammonia grid tuning, change interest rate to 6.75%, and show variable equipment life assumptions

Selective Catalytic Reduction and DLN Combustors			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$21,148,516		
Annual Capital Recovery ($/yr)	$2,976,371	$1,957,648	$1,661,684
Annual Operating Cost (excl. capital recovery) ($/yr)	$1,074,036		
Total Annual Costs ($/yr)	$4,050,407	$3,031,685	$2,735,721
Annual Emission Rate with Controls (Tons/yr)	13.3 tons/yr		
NOx Emission Reduction (Tons/year)	200.0		
Control Cost Effectiveness ($/Ton)	**$20,252**	**$15,158**	**$13,679**
Incremental Cost Effect. vs Just SCR	**$281,000**	**$199,900**	**$176,300**

Capital Cost estimate is the same as sum of costs of SCR and DLN in original NVE Four Factor Report. Operating costs are same as sum of operating costs for SCR and DLN except for some savings in Catalyst Changeout and Reagent use as shown below. Also changed interest rate to 6.75% and showing variable equipment life assumptions

Capital Recovery Factor Calculation for Different Equipment Lifes

Capital Recovery Factor = i (1+ i)n/[(1+ i)n - 1]	*0.1407*	*0.0926*	*0.0786*
(n) Equip Life years	*10*	*20*	*30*
(i) Interest Rate	*6.75%*	*6.75%*	*6.75%*

Summary of Annual Operating costs of SCR			
	Cost w/o DLN	**Cost With DLN**	
Catalyst Changeout	$191,000	$95,500	Note 1
Annual Maintenance	$38,420	$38,420	
Electrical Cost	$154,828	$154,828	
Capacity Loss - Derate	$167,435	$167,435	
Annual Ammonia Grid Tuning	$40,000	$40,000	Note 2
Reagent Usage	$129,684	$45,389	Note 3
Total Annual Cost	**$721,367**	**$394,036**	

Note 1: 50% Less frequent changeouts

Note 2: Adding this cost, per EPA Cost Manual

Note 3: 65% Less reagent with lower NOX ppm at SCR inlet

(Updated July 8, 2020)

Table 3 - 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		
- Process and Project Contingency		
Total Capital Investment	**$13,464,516**	

Annual Operating Costs Increase

There are three quantifiable operating cost impacts for DLN converstion **1) Capacity Loss from Derate** - which requires purchasing capacity, 2) **Heat rate impacts** - which requires more fuel use to generate sthe same electrcity, and 3) **not using steam** which actually saves fuel use. NVE's Resource Planning Department used the PROMOD software model to estimate the changes in operating costs associated with all these factors for a DLN conversion. This software model incorporates numerous variables such as operating unit characteristics, system operating demand, etc. to analyze scenarios for decision making and planning purposes. The PROMOD modeling estimated that the total operating cost impacts would be approximately $680,000/yr for the DLN conversion.

Operating Cost Impact	**$680,000**	$/yr capacity purchases, heat rate impacts, less steam use.
Other Operating Costs Impacts		
Cost of Handling excess Water	**Not Quantified (but estimated multiple million dollars capital)**	

Valmy Generating Station

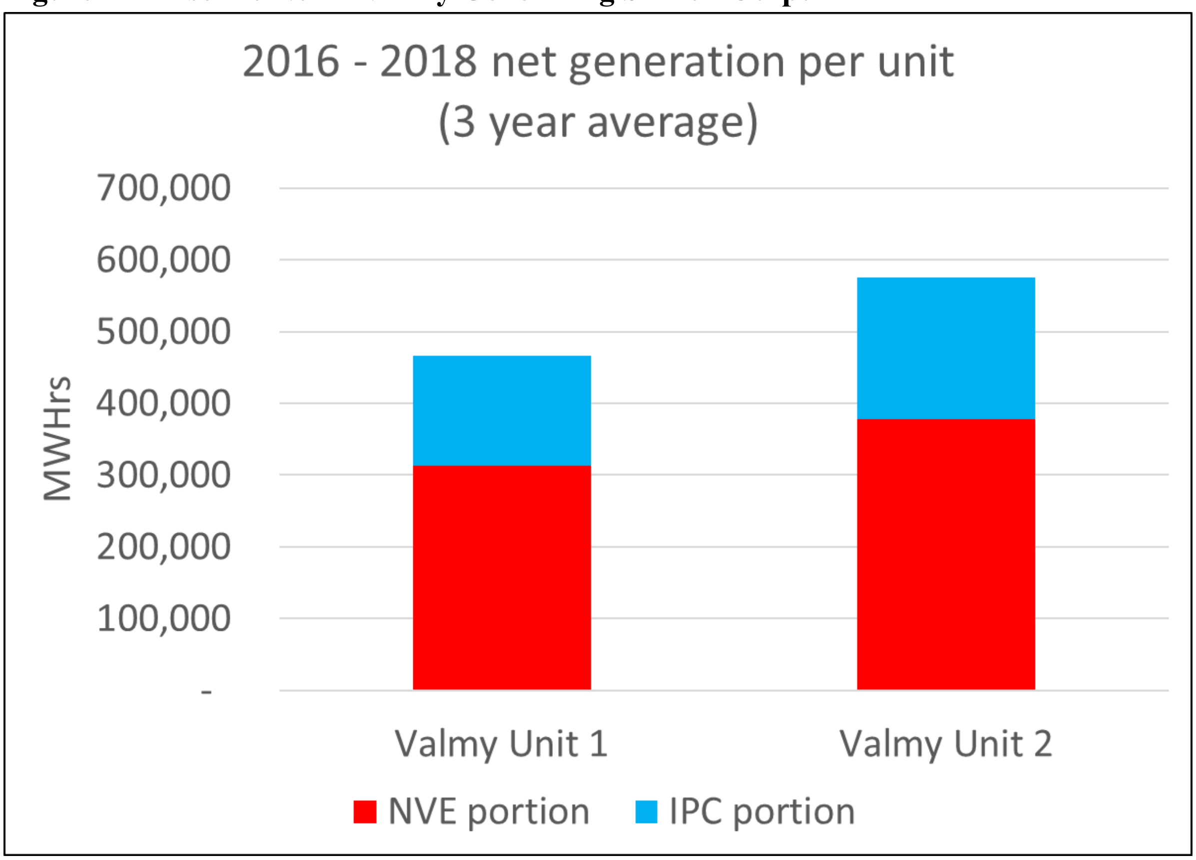
Response to 4 Factor Analysis Additional Information Request

Question (1)(a) **Further Explanation for Projected Actual 2028 Emissions**

As explained in Section 1.1.2 of the previously submitted Four Factor Analysis for North Valmy Generating Station (Valmy), the facility's generating assets are jointly owned by 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, and contractually reduced the generating capacities of the units to NVE's 50% share. As a consequence, the output of the facility is forecasted to be lower than actual output in the recent past.

The projected station output for 2028 was conservatively estimated as the average of the station's output during the 2016-2018 baseline years minus the share of that output supplied to IPC. Projected output by unit was estimated in the same fashion using each unit's baseline output and the fraction of that output that was supplied to IPC, as shown visually in Figure 1. This equates to roughly 67% of the output for Unit 1 and 65% of the output for Unit 2 in the 2028 projections as compared to the baseline output. Accordingly, the emissions projections for 2028 have been adjusted by this percent reduction in output as compared to the average annual emission totals during the baseline period. Further details about how the North Valmy Station's output and emissions were projected for 2028 are provided in Table 1 of Attachment B.

Figure 1 – Baseline North Valmy Generating Station Output



As explained in the Four Factor Analysis, this estimate of station output is more conservative (that is, higher) than the forecasted output of the station that was included in the most recent Integrated Resource Plan (IRP) filing to the Public Utility Commission of Nevada (PUCN).

Question (1)(b) **Interest Rate for Capital Recovery**

NDEP initially requested that NV Energy (NVE) recalculate the cost-effectiveness of pollution control options using an interest rate of 3.25% (equal to the current bank prime lending rate) rather than the higher interest rate that was used to annualize the capital cost of these options in NVE's previously submitted report. However, during a follow-up call with NDEP on 6/22/20, NVE explained that as a regulated utility, its cost of capital is determined differently than for an unregulated entity. NVE'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) and is not fairly represented by the current bank prime rate. The cost of capital for NVE's operating utilities consist of several components and are established triennially in a regulatory proceeding called a General Rate Case (GRC). In the most recent GRC, the PUCN established SPPC's cost of capital (i.e., its rate of return on capital investments) at 6.75%.

The attached amended cost-effectiveness tables use this 6.75% 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 Valmy) must separately go through a GRC filing and approval process with the PUCN every 3 years. 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, the PUCN-approved weighted average cost of capital is 6.75%. 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.

Question (1)(c) **SCR Equipment Life.**

NDEP has requested that NVE use an equipment life of 30 years when annualizing the capital cost of installing Selective Catalytic Reduction (SCR) on North Valmy Units 1 and 2. NVE disagrees that a 30 year life assumption is appropriate for SCR in this instance, but in the attached tables has provided a cost-effectiveness calculation on that basis as requested. As explained below, NVE believes that NVE's original assumption of an equipment life of 20 years for SCR on these units is already a very conservative estimate, because it already significantly overstates the actual anticipated remaining life of these two generating units.

NVE's North Valmy Units 1 and 2 were originally installed in 1981 and 1985, respectively. As such both units are presently already over 35 years old. Currently, Unit 1 is forecast to be retired between the end of 2021 and Unit 2 at the end of 2025. The planned retirement of the units have been communicated to the PUCN in NVE's Life Span Analysis Process (LSAP) and represent NVE's best estimate, and commitment, on life expectancy of its generating assets. As explained in Section 5.2 of the North Valmy Four Factor Report, the installation of any add-on pollution control systems is not likely to occur before 2028, at which point if Unit 1 is still in service, it will have been in operation for 47 years, and if Unit 2 remains in service it will have been in operation for 43 years. Expecting these units to continue to operate for a subsequent 30 year period beyond this point is not realistic. Therefore, NVE contends that the original economic analysis assumption of 20 years of emission control equipment life is already extremely conservative. To help NDEP understand the impact of different remaining useful life assumptions, the attached revised cost-effectiveness summaries in Tables 2 and 3 of Attachment B present a sensitivity analysis showing 10-, 20-, and 30-year equipment life cases for each emission control alternative.

Question (1)(d) <u>SCR Outlet Concentration</u>

Per NDEP's request, NVE has evaluated the technical feasibility of SCR units installed on Units 1 and 2 to achieve an outlet NOx concentration of 0.05 lb/MMBtu, as compared to the outlet concentration of 0.07 lb/MMBtu used in the previously submitted North Valmy Four Factor Analysis Report. NVE concludes that achieving an outlet emission concentration of 0.05 lb/MMBtu on these units may be technically feasible. However, NVE's engineers indicated that an increase in the estimated ammonia injection rate would be needed to achieve this outlet concentration. Accordingly the revised cost estimates associated with this alternative in Tables 2 and 3 of Attachment B utilize this outlet concentration, along with an increase in the stoichiometric ratio factor (SRF) of ammonia from 1.05 to 1.10.

Question (2) (a) <u>Flue Gas Desulfurization (FGD) Equipment Life</u>

As NDEP requested, NVE has evaluated the impact that equipment life has on the cost effectiveness of installing either limestone- or lime-based FGD systems on North Valmy Unit 1. The results of these evaluations are summarized in Table 4 of Attachment B. As described above, it is unrealistic to expect that North Valmy Unit 1 will continue to operate for 30 years beyond the date at which such systems could be expected to be installed (i.e., 30 years beyond 2028). Nonetheless, installation of FGD systems on this unit would not be cost effective regardless of what assumptions are made as to the life expectancy this equipment.

ATTACHMENT B

Revised Cost Tables for Valmy Generating Station's 4 Factor Analysis

Attachment B

Table 1 - Projection of 2028 Station Output and Emissions

	Unit 1	Unit 2	Station Total
A. Baseline Electric Output, 2016–2018 (MWhr/yr)	466,437	575,835	1,042,273
B. Baseline Output to IPC (MWhr/yr)	153,216	197,393	350,609
C. Baseline Output to SPPC (MWhr/yr) (A – B)	313,221	378,442	691,664
D. 2028 Output = Baseline Output to SPPC (MWhr/yr)	313,221	378,442	691,664
Ratio: 2028 Output/Baseline Output	0.67	0.65	
Baseline NOx Emissions (tons/yr)	804	1,002	
2028 NOx Emissions*	537	656	
Baseline SO2 Emissions (tons/yr)	1,812	501	
2028 SO2 Emissions*	1,210	327	
Baseline PM Emissions (tons/yr)	22	37.7	
2028 PM Emissions*	14.7	24.7	

**2028 Emissions = Baseline Emissions x Ratio: 2028 Output/Baseline Output*

Revised Cost Tables for NV Energy Four Factor Analysis

Table 2 – North Valmy Unit #1 - NOx Control Option Cost-Effectiveness

Selective Non-Catalytic Reduction			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)		$9,180,000	
Annual Capital Recovery ($/yr)	$1,290,000	$850,000	$720,000
Annual Operating Cost (excl. capital recovery) ($/yr)		$410,000	
Total Annual Costs ($/yr)	$1,700,000	$1,260,000	$1,130,000
Annual Emission Rate with Controls (Tons/yr)		403 tons/yr	
NOx Emission Reduction (Tons/year)		134 tons/yr	
Control Cost Effectiveness ($/Ton)	**$12,679**	**$9,389**	**$8,431**

Capital and Annual Operating Cost are same as in original NVE Four Factor Report. Only change is 6.75% interest assumption and variable equipment life assumptions

Selective Catalytic Reduction (SCR)			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)		$112,600,000	
Annual Capital Recovery ($/yr)	$15,840,000	$10,420,000	$8,850,000
Annual Operating Cost (excl. capital recovery) ($/yr)		$1,740,000	
Total Annual Costs ($/yr)	$17,580,000	$12,160,000	$10,590,000
Annual Emission Rate with Controls (Tons/yr)		80 tons/yr	
NOx Emission Reduction (Tons/year)		457 tons/yr	
Control Cost Effectiveness ($/Ton)	**$38,461**	**$26,615**	**$23,167**

Capital and Annual Operating Cost Estimates are updates to those in the original NVE Four Factor Report. Changes are a revision of the SRF for ammonia to 1.10, revision of the interest rate to 6.75%, and variable equipment life assumptions.

Table 3 – North Valmy Unit #2 - NOx Control Option Cost-Effectiveness

Selective Non-Catalytic Reduction			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)		$9,750,000	
Annual Capital Recovery ($/yr)	$1,370,000	$900,000	$770,000
Annual Operating Cost (excl. capital recovery) ($/yr)		$490,000	
Total Annual Costs ($/yr)	$1,860,000	$1,390,000	$1,260,000
Annual Emission Rate with Controls (Tons/yr)		492 tons/yr	
NOx Emission Reduction (Tons/year)		164 tons/yr	
Control Cost Effectiveness ($/Ton)	**$11,340**	**$8,481**	**$7,649**

Capital and Annual Operating Cost are same as in original NVE Four Factor Report. Only change is 6.75% interest assumption and variable equipment life assumptions

Selective Catalytic Reduction			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$130,800,000		
Annual Capital Recovery ($/yr)	$18,405,000	$12,110,000	$10,280,000
Annual Operating Cost (excl. capital recovery) ($/yr)	$2,010,000		
Total Annual Costs ($/yr)	$20,410,000	$14,120,000	$12,290,000
Annual Emission Rate with Controls (Tons/yr)	104 tons/yr		
NOx Emission Reduction (Tons/year)	552 tons/yr		
Control Cost Effectiveness ($/Ton)	**$36,936**	**$25,552**	**$22,238**

Capital and Annual Operating Cost Estimates are updates to those in the original NVE Four Factor Report. Changes are a revision of the SRF for ammonia to 1.10, revision of the interest rate to 6.75%, and variable equipment life assumptions.

Capital Recovery Factor Calculation for Different Equipment Lives

Capital Recovery Factor = i (1+ i)n/[(1+ i)n - 1]	*0.1407*	*0.0926*	*0.0786*
(n) Equip Life years	*10*	*20*	*30*
(i) Interest Rate	*6.75%*	*6.75%*	*6.75%*

Table 4 - North Valmy Unit #1 - Flue Gas Desulfurization Cost-Effectiveness

	Limestone FGD	Lime FGD
Equipment Life (years)	Cost Effectiveness ($/ton)	Cost Effectiveness ($/ton)
20	$22,626	$21,885
21	$22,160	$21,437
22	$21,757	$21,050
23	$21,397	$20,703
24	$21,079	$20,398
25	$20,782	$20,112
26	$20,507	$19,847
27	$20,274	$19,623
28	$20,040	$19,399
29	$19,850	$19,216
30	$19,659	$19,032

Appendix B.5.d - Response Letter 2

January 15, 2021

Steven McNeece
Nevada Department of Environmental Protection
901 S. Stewart Street
Suite 4001
Reno, NV 89701

Re: Response to a Second Follow-up Request for Additional Information
Regional Haze Four Factor Analyses
NV Energy Tracy (FIN 0029) and Valmy (FIN A0375) Generating Stations

Dear Mr. McNeece:

Per your email correspondence dated November 23, 2020, Nevada Power Company d/b/a NV Energy (NVE) hereby provides a response detailing Nevada Division of Environmental Protection (NDEP)'s most recent request for additional information regarding the Four Factor Analyses at both the Tracy and North Valmy Generating Stations previously submitted March 13, 2020. Please note that this is the response to NDEP's second follow-up request for additional information, as NVE also provided a response to NDEP's first follow-up request for additional information in a letter dated July 8, 2020. This letter and attachments address NDEP's most recent questions and should be considered a second addendum to the previously submitted Four Factor Analyses.

NVE appreciates the opportunity to work with NDEP in this endeavor. Please feel free to contact Sean Spitzer at (702) 402-5132 should you have any questions.

Sincerely,

Starla Lacy

Starla Lacy
Vice President, Environmental Services, Safety, and Land Resources
NV Energy

Response to NDEP's Questions on North Valmy and Tracy Generating Station's Four Factor Analyses

North Valmy Question (a) **<u>Confirm Baseline is Representative of Normal Operations</u>**

Q(a)(1) *Why were emissions so low during 2016-2018? Are these years representative of normal operations?*

A(a)(1) Calendar years 2016 - 2018 were representative of normal operations for the North Valmy Generating Station for that period of time. During this time period North Valmy transitioned from being a year-round baseload-operated resource to a resource utilized primarily to meet summer load requirements.

Q(a)(2) *Were there any shutdowns (for uncommon reasons) during 2016-2018?*

A(a)(2) There were no uncommon shutdowns at North Valmy during 2016-2018.

Q(a)(3) *Why did emissions jump in 2019? Should this year be included in the baseline?*

A(a)(3) In 2019, the output at North Valmy increased primarily as a result of economic considerations. A natural gas pipeline outage in western Canada in the late fall of 2018 drove up gas prices, thereby making coal a relatively more economic resource. NV Energy's plan had originally been to decrease utilization of North Valmy in the non-summer months due to the typically low natural gas prices that occur in these months. However, the October 9, 2018 rupture of Enbridge's BC natural gas pipeline near Prince George, British Columbia, continued to affect natural gas supply throughout the western United States, and thus market fuel prices well into 2019. The output of North Valmy Unit 1 was also higher in 2019 due to Idaho Power's exiting of their share of Unit 1's output – an action that necessitated the consumption of the coal reserves for Unit 1 that had previously been purchased by Idaho Power. Now that the gas pipeline has been repaired, fuel costs have returned to a more normal state, and thus 2020 operation to date at North Valmy has been more representative of normal operations reflected in years 2016 - 2018.

Accordingly, NVE does not consider North Valmy's operation in 2019 to be representative of normal operation and does not believe it should be included in the baseline for this analysis.

Q(a)(4) *Much like in the 4F, can NVE derive what 2019 emissions were contributed by NVE alone for each unit? Also including prior years to evaluate the trend?*

A(a)(4) The following table provides the output breakdown by ownership for each of the North Valmy units for the years 2016 – 2019.

	North Valmy Unit 1			North Valmy Unit 2		
	Output (MWhrs)	% to NVE	% to IPC	Output (MWhrs)	% to NVE	% to IPC
2016	557,595	75%	25%	525,245	77%	23%
2017	353,631	67%	33%	396,619	67%	33%
2018	610,292	62%	38%	948,853	60%	40%
2019	1,194,328	73%	27%	695,792	68%	32%

Q(a)(5) *If older years like 2014 and 2015 don't represent normal operations, please explain why.*

A(a)(5) As can be seen in the above table, the gross output of the North Valmy Station averaged 1,130,754 MWhrs in the 2016-2018 baseline period. In contrast, station output in 2014 and 2015 was much higher (2,983,412 MWhrs and 1,577,910 MWhrs, respectively). As noted previously, during 2016-2018 North Valmy transitioned to primarily a summer capacity resource. Accordingly, output and emissions from North Valmy in the 2014-2015 period are not representative of normal operations during the baseline period. However, the North Valmy units could be committed and dispatched in the non-summer months for reliability reasons, if the system experiences resource issues, or if market economics change.

Q(a)(6) *What baseline does NVE believe best represent normal operations and why?*

A(a)(6) The economics of coal-fired electricity generation no longer support operation of the facility except during times of resource scarcity and for reliability reasons. This means that electricity generation at the North Valmy Station is generally only required in the summer months. As noted previously, during 2016-2018 North Valmy transitioned to primarily a summer capacity resource. As such, NVE considers the 2016 - 2018 baseline period to be representative of normal operations.

While NDEP has requested documentation of fuel pricing to support the underlying economic basis, NVE is unable to provide fuel price information due to its highly confidential nature as explained further in the most recent triennial integrated resource plan as filed with the Nevada Public Utilities Commission (PUCN)[1]. The economic analysis included in the aforementioned integrated resource plan provides additional detail in the energy mix forecasts that, in all future scenarios, projects significantly lower expected coal generation than in the 2016-2018 baseline period[2]. Other factors contributing to Valmy's low utilization include Idaho Power's completed exit from their share of Unit 1 in 2019 and in the next few years Unit 2, 1 gigawatt of renewable energy already approved by the PUCN and scheduled to be online by the end of 2023, and Nevada's aggressive 50% renewable portfolio requirement to be met by 2030. All of these factors will further reduce the number of hours the Station may be required to operate in the near future.

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[1] Sierra Pacific Power Company d/b/a NV Energy and Nevada Power Company d/b/a NV Energy's Application seeking approval of their joint triennial integrated resource plan (addressing the twenty-year planning period 2019 to 2038 and action plan period 2019 to 2021) and energy supply plans (addressing the three year period 2019 to 2021). Docket No. 18-06003, Document ID 30439, p4. Accessed January 11, 2021, via State of Nevada Public Utilities Commission webpage at:
http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2018-6/30439.pdf

[2] Sierra Pacific Power Company d/b/a NV Energy and Nevada Power Company d/b/a NV Energy's Application seeking approval of their joint triennial integrated resource plan (addressing the twenty-year planning period 2019 to 2038 and action plan period 2019 to 2021) and energy supply plans (addressing the three year period 2019 to 2021). Docket No. 18-06003, Document ID 30459, p244-247. Accessed January 11, 2021, via State of Nevada Public Utilities Commission webpage at:
http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2018-6/30459.pdf

North Valmy Question (b) **More Documentation of Suggested Interest Rate for Capital Recovery**

Per NDEP's request, please find Attachment I showing NV Energy's September 24, 2019 filing with PUCN stipulating that the overall cost of capital in the annual revenue requirement for general rates charged to electricity customers for the current period is 6.75%. Please see Item 4 of the Agreement section of the filing for further details. NV Energy confirms that this is its most recent filing with the PUCN that addresses the return on capital that NVE is permitted to receive.

North Valmy Question (c) **Consideration of Additional SO2 Controls for North Valmy**

Dry Sorbent Injection (DSI)

NDEP requested that NVE evaluate the use of DSI as a sulfur dioxide (SO2) emission control alternative for North Valmy Unit 1.

The two Four Factor Analyses for other electric generating stations that addressed DSI as an SO2 emissions control alternative that NDEP provided were reviewed[3,4]. Both studies conclude that DSI is a technically feasible means to control SO2 emissions from coal-fired power plants. However, in each study DSI was evaluated as an option involving operating in conjunction with and to improve the SO2 control efficiency of an existing flue gas desulfurization (FGD) system. Accordingly, the facilities in both of these studies are quite different than North Valmy Unit 1. Furthermore, both studies concluded that the use of DSI was inferior to other alternatives to reduce SO2 emissions.

NVE investigated the feasibility and cost associated with the use of DSI as a means to control SO2 emissions from North Valmy Unit 1 in 2012 in conjunction with developing compliance strategies for the electric utility Mercury and Air Toxics Standards (MATS) rules (codified under 40 CFR 60 Subparts D, Da Db and Dc, and 40 CFR 63 Subpart UUUUU). Under these rules, utility generating plants are required to meet numeric emission limits for HCl, but may choose to comply with an SO2 emission limit as an alternative to meeting the HCl emission limits. The DSI investigation for North Valmy was based on a demonstration program for this technology that was conducted in July 2012 on the unit. It concluded that while it was technically feasible to utilize DSI to meet the MATS emission limit for SO2 (0.2 lb/MMBtu), sorbent injection causes an increase in the oxidation of nitric oxide (NO) to nitrogen dioxide (NO2) in the unit's flue gas, which led to the formation of a visible brown plume from the unit's exhaust stack.

Based on cost information presented in this previous investigation, the installation of DSI on North Valmy Unit 1 would entail a total capital cost of $37,421,000 and utilization of this alternative would entail a total annualized cost impact of $6,702,000 per year to meet the MATS SO2 emission limit of 0.20 lb SO2/MMBtu. Achieving this limit at the projected future annual operating level of North Valmy Unit 1 presented in the Four Factor Analysis (313,221 MWhr/yr in 2028) would represent a decrease in SO2 emissions of 891.7 tons SO2/yr compared to uncontrolled emissions. Therefore, the cost effectiveness of this alternative is $7,516 per ton controlled.

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[3] "North Dakota Round II Regional Haze State Implementation Plan Determination's Four-Factor Analysis for Antelope Valley Station Units 1 and 2," Sargent & Lundy, LLC January 30, 2019.

[4] "Coyote Station Unit 1: North Dakota Regional Haze Second Planning Period Four-Factor Analysis," Sargent & Lundy, LLC May 8, 2019.

DSI would accordingly provide less SO2 control at somewhat lower cost than either of the two alternatives evaluated in the Four Factor Analysis submitted for North Valmy (limestone and lime-based flue gas desulfurization). Nonetheless considering that the projected future output level of the station is relatively low (as discussed in Section 1.1.2 of the Four Factor Analysis), NV Energy does not consider DSI to represent a cost-effective alternative to control SO2 emissions.

Dry Lime FGD System Upgrades

NDEP requested that NVE evaluate upgrades to the existing dry lime FGD system for SO2 control on Valmy Unit 2, including improvements associated with limestone quality, Ca:S ratio, liquid to gas ratio, as well as system design improvements such as additional lime slurry spray level, spray level coverage, and pH buffer additive.

NVE has made numerous upgrades to the existing FGD system on North Valmy Unit 2 since it was originally installed. The results of these improvements are most clearly understood within the context that the system's current SO2 removal efficiency (approximately 80% based on 2020 operating data) is considerably higher than the system's original design specification (70%).

NVE already utilizes the highest quality lime that is commercially available at the North Valmy Station; the calcium content specification for the quicklime reagent is 93% calcium oxide (minimum). Improvements have been made to the operating Ca:S ratio, specifically the reagent injection rate has been increased in response to having to meet the MATS emission level on Unit 2 and the injection of reagent into each spray dryer vessel has been upgraded to include the use of recycled system ash as well as fresh lime in order to increase the surface area available for the lime-SO2 reaction to occur.

The system currently operates at the lowest feasible saturation approach temperature (approximately 30-50°F above the flue gas dew point) in order to prevent scale formation on the spray dryer walls and to prevent baghouse bag fouling. The lime slurry spray coverage in each vessel has already been optimized; each vessel is equipped with three levels of atomization. Because lime slurry is abrasive, atomizers wear out regularly and so a full set of spare atomizers is maintained on site.

Finally, the lime slaking process has been optimized to produce the smallest possible lime particle size, as maximizing lime particle surface area per particle volume is a key operational consideration. Water used for lime slaking is preheated to 100°F using steam spargers and the temperature of the slaking process is closely monitored to prevent excessive temperature rise, which can cause the thixotropic lime slurry to become unpumpable.

In summary, the lime spray dryer FGD system on North Valmy Unit 2 has already been upgraded with most of the operational and design improvements described by the referenced studies.

North Valmy Question (d) **<u>SCR Retrofit Factor</u>**

NDEP requested that NVE provide additional justification for the use of a retrofit factor of 1.3 for estimating the cost of Selective Catalytic Reduction (SCR) on North Valmy Units 1 and 2. Specifically, NVE was asked to "…provide details on the extent of available space limitations in the boilers' vicinity, the new steel structures to support the SCR, the capacity limitations on existing forced and ID fans, and the additional large-capacity ductwork."

In 2009, NV Energy engaged Sargent & Lundy (S&L) to evaluate the technical feasibility of retrofitting North Valmy Units 1 and 2 with SCR systems to control NOx emissions. This study included a comprehensive assessment of the physical changes that would be needed to implement this technology on each boiler. S&L concluded that each boiler's induced draft fan performance would be adversely affected by the additional pressure drop that the addition of SCR would cause, requiring replacement of the ID fan motors and possible replacement of the fan rotors. Modifications to the plant's auxiliary power system would also be required to accommodate the larger ID fan motors. The study noted that supporting the SCR reactors and required ductwork for each boiler would be "challenging" and that less space in the vicinity of Unit 1 was available for locating the required equipment relative to space near Unit 2. For Unit 1, S&L estimated that an SCR retrofit would require a total of 345 tons of new boiler ductwork or ductwork modifications, along with 1,100 tons of new support steel or reinforcement to existing support steel structures. For Unit 2, S&L estimated that 390 tons of new ductwork or ductwork modifications would be needed, as well as 985 tons of new support steel or support steel reinforcements. Finally, the S&L study identified that possible relocation of below-grade utility lines may be needed depending on where the ammonia storage and vaporization equipment would be located.

Moreover, the use of SCR on either Unit 1 or Unit 2 would not be cost effective even if a 1.0 retrofit factor were to be used to estimate the capital cost of this alternative. For Unit 1, the estimated capital cost for SCR using a 1.0 retrofit factor is $85.4 million, and the estimated annual cost of this alternative is $9.44 million per year. Using the annual NOx reduction level for this alternative presented in the Four-Factor report (425 tons/yr), even with a 1.0 retrofit factor this alternative would have a cost effectiveness of over $22,000 per ton removed. For Unit 2, the estimated capital and annualized costs of SCR with a 1.0 retrofit factor are $99.2 million and $10.95 million per year, respectively, resulting in a cost effectiveness of over $21,000 per ton removed.

Tracy Question (a) **<u>Capacity Loss for Derate</u>**

NDEP requested clarification and justification regarding the difference between the costs associated with 1) capacity loss for derate and 2) annual electricity cost.

Adding SCR to this gas turbine would introduce pressure drop that would have two impacts: 1) slightly decrease the maximum power generating capacity of the turbine (derate); and 2) increase the amount of fuel needed to generate the same amount of electricity (power/electricity cost). These are two distinctly separate, but related costs. However, upon further review, NVE now believes that the electricity costs estimated using the EPA CCM formula for electricity costs adequately covers the total of both of these items. That value, characterized as the "annual electricity cost" of $154,000 in NVE's original Four Factor report is sufficient to estimate both of these impacts, and the separate derate cost can be dropped from the analysis of SCR for this turbine.

Nevertheless, the following paragraphs explain the original reason for including both of the above costs and NVE's reason to now revise our assessment.

The "derate costs" relates to NVE's responsibility to have a certain amount of maximum generating capacity available to meet potential system demands – whether that capacity is used or not. Since SCR's pressure drop would reduce the maximum capacity of this generator, NVE needs to make up for this lost generating capacity by either building additional capacity or purchasing capacity externally. This is the cost to have generating capacity available, regardless of whether it is used.

The power/electricity cost (Item 2 above) relates to the extra costs to actually generate a given amount of electricity which either requires additional fuel to overcome the SCR pressure drop (if this unit is running below full load) or the cost to purchase or make replacement electricity if the turbine is already at full load.

NVE's original estimate used EPA's CCM electricity formula to characterize the second above item, power/electricity cost, but a separate basis to estimate the cost for capacity purchases. However, NVE now feels the EPA CCM value is sufficient for both items. NVE reached this conclusion based on a recently completed, detailed evaluation of the overall power and capacity costs for the derate of another unit. For that analysis, NVE's Resource Planning Department used the PROMOD software model which incorporates numerous variables such as operating unit characteristics, system operating demand, etc. to analyze scenarios for decision making and planning purposes. Applying the results of that analysis to the derate of Tracy Unit 6 indicates that the total electricity and derate cost impacts are adequately covered in the electricity cost value of $154K/yr using EPA's CCM method. Therefore, NVE now believes that using just that one cost based on EPA's CCM method (and not a separate additional cost for a derate) adequately covers the fuel, auxiliary power and derate lost capacity impacts of the SCR catalyst pressure drop.

NVE has updated our cost-effectiveness analysis of SCR for Unit 6 excluding the derate costs in Attachment C. Adopting this change, together with the other items noted in the responses to the other below NDEP questions, lowers the cost effectiveness of SCR for Unit 6 to $6,080/ton NOx removed (assuming 20 yr life, or $5,500/ton for 30 year life) which is slightly lower than the $7,300/ton in NVE's original analysis.

Tracy Question (b) **<u>Catalyst Changeout Cost Based on Future Worth Factor</u>**

NDEP indicates that the EPA CCM equations for SCR catalyst changeouts show expected costs of $79,000/yr which is lower than NVE's $191,000/yr which is based off a catalyst change at NVE's Silverhawk Generating Station. NDEP requests justification as to why the Silverhawk unit is similar to Unit 6 and is appropriate to use in this estimation.

The Silverhawk unit is larger on a MW basis than Tracy Unit 6, but has similar inlet NOx lbs/hr. However, the primary difference in NVE's higher estimated cost is unrelated to the unit's size or NOx removal requirements, but is because of two other factors: 1) NVE had assumed a different catalyst changeout frequency than the default assumption in the EPA CCM and 2) NVE assumed a higher cost per cubic feet for the catalyst replacement and disposal than the EPA CCM default cost value. Each of these items is discussed below. Also, NVE has calculated a revised catalyst annual cost value using the EPA CCM equation, but with updated catalyst cubic foot cost data. This updated estimate is presented in Attachment D and discussed below.

Catalyst Changeout Frequency:

It should be first noted that there are two methodologies for estimating annual SCR catalyst costs in the EPA CCM. NVE assumes that NDEP used Methodology 1, which yields a lower cost than the more generic Methodology 2. One of the default assumptions in the EPA cost manual examples for Methodology 1 is that an SCR system will replace one of its multiple catalyst layers every 3 years. For an SCR reactor with 3 catalyst layers (e.g. the example in the EPA CCM), one would only changeout 1/3 of the total catalyst volume each 3 years, resulting in an average of 9 years of operation before all of the catalyst would be changed. NVE had instead originally assumed a total changeout every 5 years but is comfortable with revising that assumption to use the EPA example assumption (1/3rd changed each 3 years).

Catalyst replacement and disposal costs $/ft3:

EPA cost control manual and EPA on-line SCR cost spreadsheets contain a default value of $227/ft3 for the total cost for materials, labor and disposal to replace SCR catalyst. NVE assumes that NDEP used this value in their estimate. However, NVE's recent experience with an SCR catalyst changeout at the Silverhawk facility indicates that current catalyst changeout costs on a $/ft3 basis are actually higher.

NVE is unclear the basis of the EPA CCM catalyst replacement cost of $227/ft3.[5] But regardless of the basis of the $227/ft3 example value, the EPA CCM indicates that the current costs of catalyst, installation, and disposal of the old catalyst should be used. NVE believes that the catalyst replacement costs on a $/ft3 basis from NVE's recent SCR catalyst replacement at another of NVE's operating facilities would be more representative and appropriate of the current costs.

NVE recently replaced 2,294.5 cubic feet of SCR catalyst on Silverhawk Unit A for a total catalyst replacement project cost of $1.08 million. This equates to a replacement cost of $469/ft3. This total cost includes $838.5 K for the contractor's turnkey costs for catalyst procurement and replacement, a contract project manager and scaffolding. The remainder of the $1.08 million ($237 K) is for NVE's own plant labor costs, testing, and related engineering. However, even excluding NVE's labor cost, testing and other engineering, the $838.5 K cost alone equates to $365/ft3 for the catalyst replacement. NVE believes, at a minimum, this $365/ft3 value is an appropriate and conservative estimate of the per cubic foot costs for SCR catalyst replacement. A breakdown of these Silverhawk catalyst changeout costs are shown in Attachment E and the catalyst replacement cost of $365/ft3 is used in the revised annual catalyst cost calculation in Attachment D.

Using the EPA CCM Methodology 2, and the above described $365/ft3 replacement cost yields an updated estimate for SCR annual catalyst cost of $140,000/yr as shown in Attachment D. This is a little lower than NVE's earlier estimate. This updated value is used in the revised cost-effectiveness calculation in Attachment C.

Tracy Question (c) **Reagent Cost**

NDEP requests documentation that confirms the reagent concentration (19%) and reagent cost (0.95 $/gallon).

Ammonia unit costs vary over time, are different at different locations (related to shipping and supplier costs), vary based on the size of the shipment (large bulk deliveries are cheaper than non-bulk deliveries), and vary by supplier. NVE's estimate of $0.95/gal for 19% ammonia solution for the Tracy Unit 6 was based on consideration of several vendor prices quotes in 2019. However, the current very lowest vendor price for a large bulk delivery of 19% ammonia for Tracy is currently 0.0776 /lb, which equates to

[5] The EPA CCM references that the $227 / ft3 catalyst cost assumption is from a Sargent and Lundy study from 2017, which itself references a previous Sargent and Lundy study from 2013, which references "2004 to 2006 industry cost estimates for SCR units".

$0.61/gal. Attachment F shows a copy of a recent Purchase Order reflecting this unit price from NVE to Airgas for an ammonia purchase for use for the SCR system on a different Tracy unit.

Ammonia prices have been higher in the past and may increase in the future, thus this value may not be appropriate for budgeting or decision-making purposes. Also, the area around Unit 6 at Tracy is very congested and may not have room for a large ammonia tank that can accommodate a delivery that would qualify for this bulk price. For context on the range of ammonia pricing, NVE has provided a table in Attachment G displaying recent price quotes from suppliers of 19% ammonia for both bulk and non-bulk shipments to its power generating stations. Nevertheless, revising this cost does not significantly impact the economics of SCR for Tracy Unit 6. To illustrate this sensitivity, NVE has substituted the reagent cost of $0.61/gal into our updated SCR cost-effectiveness analysis shown in Attachment C.

Tracy Question (d) **<u>Ammonia Grid Tuning</u>**

NDEP noted that NVE included $100,000 in the Total Capital Investment for ammonia grid tuning, as well as an additional $40,000 in annual costs. NDEP requested justification for the additional $100,000 and clarification whether these costs represent the same thing?

The NDEP referenced $100,000 included in the Total Capital Investment is the initial SCR system performance testing and tuning. This performance testing in year "zero" is a separate activity than the future annual tuning.

The initial testing of the SCR system is a legitimate cost to include in a capital cost estimate. For Unit 6, the capital cost estimate for the SCR system was based on a vendor quote specific to this unit but did not include startup support or initial performance testing. EPA's CCM section describing general cost estimate methodologies states that total capital investment costs should include *"start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees)"*.[6] The EPA CCM section on SCR presents a simplified equation to calculate total capital costs based on the size of the unit and a few other parameters but doesn't itemize individual components of the cost. Presumably it includes startup support and testing. NVE did not use the EPA CCM SCR capital cost equation because it is for boilers – not gas turbines. However, it is noteworthy that the EPA CCM SCR capital cost equations for natural gas fired boilers, if applied to the MW size of this gas turbine, would yield total capital cost higher than the NVE's estimate for this unit based on a vendor quote even including this startup and performance testing cost.

The above describes why including initial performance testing in the capital costs is appropriate. Further details of the basis of the $100,000 cost estimate for this work was provided in NVE's response to NDEP's questions in July 2020.

As to the separate $40,000 annual tuning cost which NVE included in annual operating costs of SCR for this unit—these costs are based on the midrange of the typical tuning costs discussed in the EPA CCM which NDEP mentioned above (from $30,000 to $50,000). EPA's CCM indicates that the ability of an ammonia injection grid to achieve good mixing can decline over time and that annual tuning can return the AIG to startup or near-startup mixing uniformity. Tuning is also recommended when catalyst is

[6] EPA Cost Control Manual Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology, Nov. 2017, page 9

replaced. Tuning and testing is specifically not included in the separate catalyst changeout cost basis discussed previously.

Tracy Question (e) **Labor Rate Web Link**

NDEP indicated that the previously provided labor rate web link is invalid and requested a correct link.

The website link provided in NVE's July response to NDEP's previous question on this topic was valid when re-checked by NVE but does require some navigation from the initial page that comes up when the site is accessed. The correct weblink to the website for relevant section of the US bureau of Labor Statistics website is:

https://data.bls.gov/oes/#/occGeo/One%20occupation%20for%20multiple%20geographical%20areas

To help NVE navigate this website, NVE provides as Attachment H four pages of printouts of the Bureau of Labor Statics website showing the various options that need to be selected to access the data relevant to this analysis.   In summary, NVE used this US government database to determine the average labor rate for pipefitters and steam fitters (a typical labor type for this type of work) in the Reno, NV area versus the national average. At the time of NVE's original Four Factor Analysis the then current Bureau of Labor Statics website showed a 9% higher labor rate in the Reno area for this labor category.   However, NVE used a lower more conservative assumption of 5%.   Accessing this Bureau of Labor Statistics on Dec. 30, 2020 to respond to NDEPs new request, NVE observed that the more recently available data on the website now shows a 13% higher labor rate for the Reno area versus the national average for this labor category.   This makes NVE's 5% labor rate adjustment even more conservative.

(Attachments)

Attachment A
Projection of 2028 Station Output and Emissions

	Station Total	Unit 1	Unit 2
A. Electric Output, 2016–2018 Baseline (MWhr/yr)	1,042,273	466,437	575,835
B. Baseline Output to IPC (MWhr/yr)	350,609	153,216	197,393
C. Baseline Output to SPPC (MWhr/yr) (A – B)	691,664	313,221	378,442
D. 2028 Output = Baseline Output to SPPC (MWhr/yr)	691,664	313,221	378,442
Ratio: 2028 Output/Baseline Output		0.67	0.65
Baseline NOx Emissions (tons/yr)		804	1,002
2028 NOx Emissions*		537	656
Baseline SO2 Emissions (tons/yr)		1,812	501
2028 SO2 Emissions*		1,210	327
Baseline PM Emissions (tons/yr)		22.0	37.7
2028 PM Emissions*		14.7	24.7

*2028 Emissions = Baseline Emissions x Ratio: 2028 Output/Baseline Output

Attachment B
Revised Cost Tables for NV Energy Four Factor Analysis

Table 1 – North Valmy Unit #1 - NOx Control Option Cost-Effectiveness

Selective Non-Catalytic Reduction			
	10-year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)		$9,180,000	
Annual Capital Recovery ($/yr)	$1,290,000	$850,000	$720,000
Annual Operating Cost (excl. capital recovery) ($/yr)		$410,000	
Total Annual Costs ($/yr)	$1,700,000	$1,260,000	$1,130,000
Annual Emission Rate with Controls (Tons/yr)		403 tons/yr	
NOx Emission Reduction (Tons/year)		134 tons/yr	
Control Cost Effectiveness ($/Ton)	**$12,679**	**$9,389**	**$8,431**

Selective Catalytic Reduction (SCR)			
	10-year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)		$112,600,000	
Annual Capital Recovery ($/yr)	$15,840,000	$10,420,000	$8,850,000
Annual Operating Cost (excl. capital recovery) ($/yr)		$1,740,000	
Total Annual Costs ($/yr)	$17,580,000	$12,160,000	$10,590,000
Annual Emission Rate with Controls (Tons/yr)		80 tons/yr	
NOx Emission Reduction (Tons/year)		457 tons/yr	
Control Cost Effectiveness ($/Ton)	**$38,461**	**$26,615**	**$23,167**

Table 2 – North Valmy Unit #2 - NOx Control Option Cost-Effectiveness

Selective Non-Catalytic Reduction			
	10-year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$9,750,000		
Annual Capital Recovery ($/yr)	$1,370,000	$900,000	$770,000
Annual Operating Cost (excl. capital recovery) ($/yr)	$490,000		
Total Annual Costs ($/yr)	$1,860,000	$1,390,000	$1,260,000
Annual Emission Rate with Controls (Tons/yr)	492 tons/yr		
NOx Emission Reduction (Tons/year)	164 tons/yr		
Control Cost Effectiveness ($/Ton)	**$11,340**	**$8,481**	**$7,649**

Selective Catalytic Reduction			
	10-year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$130,800,000		
Annual Capital Recovery ($/yr)	$18,405,000	$12,110,000	$12,290,000
Annual Operating Cost (excl. capital recovery) ($/yr)	$2,010,000		
Total Annual Costs ($/yr)	$20,410,000	$14,120,000	$14,280,000
Annual Emission Rate with Controls (Tons/yr)	104 tons/yr		
NOx Emission Reduction (Tons/year)	552 tons/yr		
Control Cost Effectiveness ($/Ton)	**$36,936**	**$25,552**	**$22,238**

Table 3 – North Valmy Unit #1 - Flue Gas Desulfurization Cost-Effectiveness

Equipment Life (years)	Limestone FGD	Lime FGD
20	$22,626 /ton	$21,885 /ton
21	$22,160 /ton	$21,437 /ton
22	$21,757 /ton	$21,050 /ton
23	$21,397 /ton	$20,703 /ton
24	$21,079 /ton	$20,398 /ton
25	$20,782 /ton	$20,112 /ton
26	$20,507 /ton	$19,847 /ton
27	$20,274 /ton	$19,623 /ton
28	$20,040 /ton	$19,399 /ton
29	$19,850 /ton	$19,216 /ton
30	$19,659 /ton	$19,032 /ton

Attachment C

Revised Cost Tables for NV Energy Four Factor Analysis

Tracy Unit #6/Piñon Pine 4 - SCR NOx Control Option Cost-Effectiveness

Table C-1 SCR Operating Cost Assumption Changes

SCR Operating Costs (Current cost assumptiosn are shown compared to most recent estimate sent to NDEP July 8, 2020.)	Previous Basis (July 2021 Response to NDEP)	Jan. 2021 Updated Estimate	Jan. 2021 Update for SCR w/DLN
Capacity Loss from Derate (1)	$167,435	(included)	(included)
Power Cost due to SCR Pressure Drop	$154,828	$154,828	$154,828
Catalyst Changeout Costs (annualized with FWF) (2, 3)	$191,000	$140,000	$70,000
Annual Maintenance Costs	$38,420	$38,420	$38,420
Annual Ammonia Grid Tuning	$40,000	$40,000	$40,000
Reagent Usage (4)	$129,684	$83,271	$29,145
Total Annual Operating Costs (excluding Capital Recovery)	**$721,367**	**$456,519**	**$332,393**

Notes

1) Assume Derate costs covered in Power costs. No need for extra cost line item.

2) Updated Catalyst Changeout costs per Attachments D and E.

3) With DLN, assume lower inlet NOx allows 50% less frequent changeouts (same assumption)

4) With DLN, assume 65% Less reagent with lower NOx ppm at SCR inlet (same assumption)

Table C-2 SCR Cost Effectiveness (Updated Jan. 2021)

Selective Catalytic Reduction w/existing steam injection			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$7,684,000		
Annual Capital Recovery ($/yr)	$1,081,420	$711,282	$603,748
Annual Operating Cost (excl. capital recovery) ($/yr)	$456,519		
Total Annual Costs ($/yr)	$1,537,939	$1,167,801	$1,060,267
Annual Emission Rate with Controls (Tons/yr)	21.3 tons/yr		
NOx Emission Reduction (Tons/year)	192.0		
Control Cost Effectiveness ($/Ton)	**$8,010**	**$6,082**	**$5,522**

Capital Cost estimate is the same as in original NVE Four Factor Report and July update. Changes to operating costs versus NVE's July 2020 response to NDEP questions is shown in Table C-1 above. Cost-effectiveness is shown for multiple equipment life assumptions.

Capital Recovery Factor Calculation for Different Equipment Lifes

Capital Recovery Factor = i (1+ i)n/[(1+ i)n - 1]	*0.1407*	*0.0926*	*0.0786*
(n) Equip Life years	*10*	*20*	*30*
(i) Interest Rate	*6.75%*	*6.75%*	*6.75%*

Attachment C - Revised SCR Cost-Effectiveness (continued)

The below table shows cost-effectiveness of SCR if paired with a DLN converstion which was the subject of an earlier question by NDEP (not in NDEP's most recent request).

Table C-3 SCR Cost Effectiveness (Updated Jan. 2021)

Selective Catalytic Reduction and DLN Combustors			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$21,148,516		
Annual Capital Recovery ($/yr)	$2,976,371	$1,957,648	$1,661,684
Annual Operating Cost (excl. capital recovery) ($/yr)	$1,012,393		
Total Annual Costs ($/yr)	$3,988,763	$2,970,041	$2,674,077
Annual Emission Rate with Controls (Tons/yr)	13.3 tons/yr		
NOx Emission Reduction (Tons/year)	200.0		
Control Cost Effectiveness ($/Ton)	**$19,944**	**$14,850**	**$13,370**
Incremental Cost Effect. vs Just SCR	**$306,400**	**$225,300**	**$201,700**

Capital Cost estimate is the same as sum of costs of SCR and DLN in original NVE Four Factor Report and July update. Operating costs for SCR are updated as discussed above. Operating costs for DLN are same as NVE's July 2020 update.

Attachment D: Estimate of SCR Catalyst Annual Costs

NVE estimated the annual price for SCR catalyst using EPA's Cost Control Manual Methodology 1. This method using 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 Costs per EPA Cost Control Manual Method 1

Turbine Design Parameters			**Tracy Unit 6 (Pinon Pine #4)**
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	8.49	MMBtu/MW (actual 2016-2018 average)
	Days of Operation	365	days/yr
NOx_{in}	Inlet NOx	0.1515	lb/mmbtu (actual 2016 - 2018 average)
	% control	90.00	% removal for SCR (assumed)
Sulf	Fuel Sulfur Content	0	weight fraction (negligible for Natural Gas)
SCR Assumptions:			
N_{scr}	Number of SCR Reactor Chambers	1	Chambers (EPA default in EPA SCR spreadsheet and CCM)
Rl_{ayer}	Number of Catalyst Layers	3	layers (EPA default)
Slip	Ammonia Slip Design	2	ppm (EPA default)
T	Gas Temp. at SCR Inlet	650	F (EPA Default)
Other Parameters			
i	Interest Rate	6.75%	
y	Frequency of Cat. Changeout	3	Years (assume only replace one layer on this frequency, EPA CCM default)
$CC_{replace}$	Catalyst Cost	365	$/ft3 (includes removal, disposal and install.) This is a conservate estimate (see Attach. E)

Actual catalyst costs for NVE at the Silverhawk facility in 2018 were $469/ft3.

Calculated values and adjustment Factors for estimating Catalyst Volume

Q_B	Max. Heat Input Rate	908.43	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}	0.9010		$= 0.8524 + (0.3208 * NOx_{in})$
S_{adj}	0.9636		$= 0.9636 + (0.455 * Sulf)$
T_{adj}	1.146		$= (15.16 - (0.03937 * T) + (0.0000274 * (T)^2))$
FWF	Future Worth Factor	0.31181	$= i*(1/((1+i)^y-1))$

Attachment D: Estimate of SCR Catalyst Annual Costs (continued)

SCR Calculated Catalyst Volume (entire reactor) EPA CCM Methodology 1

Vol_{cat}	Catalyst Volume	3682.42	ft3 (calculated)

Catalyst Volume (ft3) = 2.81 x Q_B x EF $_{adj}$ x $Slip_{adj}$ x NOx_{adj} x S_{adj} x (T_{adj}/N_{vfu})

Calc. Annual Catalyst Costs (assuming only one layer (1/3 of total) catalyst is replaced each Changeout.

Annual Catalyst Cost w/365 \$/ft3	**\$139,701**	**\$/yr** = N_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF
		(FYI - one time cost to change entire catalyst)
	\$1,344,085	= Nscr x Volcat x CCreplace

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*	***\$179,506***	***\$/yr*** *=* N_{scr} *x* Vol_{cat} *x (*$CC_{replace}$*/*R_{layer}*) x FWF*

Attachment E: Estimate of SCR Catalyst Unit Pricing ($/cubic foot)

NVE estimated the unit price for chanegout of a cubic foot of SCR catalyst based on the actual pricing for the 2018 changeout of the catalyst at the Silverhawk Unit A generating unit. Below is a breakdown of the actual costs for the changeout and the total catalyst volume (cubic feet). The replacement costs include the cost of the catalyst itself, disposal of the spent catalyst, labor for the work, and other associated costs as shown below.

(A)	**Total SCR Catalyst Volume**	**2294.5**	**ft3**
	Costs of Silverhawk 2018 Changeout		
	<u>Base Catalyst Changeout Costs</u>		
	Contract price for Catalyst Procurement and Replacment	$765,500	See contractor bid price breakdown on next page
	Contract Project Manager	$53,000	
	Scaffolding	$20,000	
(B)	**Subtotal of Above**	**$838,500**	
	Cost/ft3	**$365**	(B)/(A)
	<u>Other Catalyst Changeout Project Costs</u>		
	Environex (Testing and Tuning)	$22,700	
	Air Hygiene Testing (initial baseline)	$39,000	
	Outlet Grid Testing	$38,500	
	NVE Plant Labor Costs	$121,000	
	Addit. Engineering from FEMCO	$15,375	
	Subtotal of other costs	$236,575	
(C)	**Total all costs**	**$1,075,075**	
	Cost/ft3	**$469**	(C)/(A)

The unit cost of 469$/ft3 is the total cost associated with the SCR catalyst changeout at Silverhawk. However, to illustrate the most conservative basis, NVE has used the subtotal cost of $365 to estimate the annual catalyst cost of SCR for the Four Factor Analysis of Tracy Unit 6. Actual unit costs are expected to be the higher value.

Attachment E: Estimate of SCR Catalyst Unit Pricing ($/cubic foot) (Continued)

EXHIBIT B PRICING SCHEDULE

The following pricing schedule shall apply to this Contract:

Catalyst Procurement and Replacement on HRSG A at Silverhawk

Contract Price –

Nevada Power Company d/b/a NV Energy

01	**Mobilization and Demobilization Cost** – (Mobilization costs not to exceed 5% of the total cost of the project)	
	(a) Material Costs	$10,000.00
	(b) Labor Costs	$10,000.00
	(c) Other Cost Excluding Material and Labor	$10,000.00
	Firm Fixed Lump Sum Cost for Line Item 01:	**$30,000.00**
02	Enter the Cost for all **Labor, Materials, Equipment and Installation**, Excluding Mobilization & Demobilization Cost to provide:	
	(a) Material –	$22,677.64
	(b) Labor Costs -	$34,240.00
	(c) Equipment Cost -	$424,084.53
	(d) Installation Cost	$22,500.00
	(d) Other Cost Excluding Materials and Labor -	$158,032.00
	Firm Fixed Lump Sum Cost for Line Item 02:	**$661,543.17**
03	Payment and Performance Bonds	$12,013.27
Total Firm Fixed Price for Lines 01 through 03:		**$703,547.44**
04	5-Year Warranty to include Material and Workmanship:	$61,952.56
Contract Price for All Costs in Lines 01 thru 04:		**$765,500.00**

Attachment F

Purchase Order for 19% Aqueous Ammonia Bulk Delivery to Tracy

PURCHASE ORDER

Sierra Pacific Power Company (dba NV Energy)

Send Invoice To:	**Purchase Order : 00203672R00034**
NV Energy, Accounts Payable	**Revision :** **Release :** 00034
PO BOX 10100	**Date Printed** : 11/30/20
RENO, NV 89520-0024	**Page Number** : 1
Email to: APinvoice@nvenergy.com	

Counterparty:
AIRGAS SPECIALTY PRODUCTS INC
930 MT VERNON AVE
COLTON CA 92324
Attn: JOHNNY GILBERT (f)909.783.937

Please Direct Inquiries to:
ABIGAIL WATKINS
Title : ASSOC BUYER
Dept : Procurement
Phone: (702)402-2949 **Ext:**
Fax :
awatkins@nvenergy.com

****** BLANKET ORDER RELEASE ******

Payment Terms : % **Days Net** 30 **Days** **ERS:** N **Ref Contract:**

Primary Ship To: SIERRA PACIFIC POWER COMPANY
Dlvr 6:30-11:30a,12:00-5p M-Th
Tracy Power Station
1799 Waltham Way
Sparks NV 89437
ATTN:Arletta Abraham

Transit type :
Carrier Name : VENDOR DELIVERY
FOB : FREIGHT ALLOWED
FOB Point : DESTINATION

Instructions & Notes

NOTE NOT ALL NVE WAREHOUSES HAVE
LOADING DOCK THEREFORE LOAD MUST BE
BROUGHT TO TAILGATE OR END OF TRUCK OR
VENDOR TO NOTIFY WAREHOUSE IF ONE IS
REQUIRED
THIS BLANKET PURCHASE ORDER (BPO)
IS TO PROVIDE A FUNDING AND INVOICE
REFERENCE FOR AIRGAS
TO PERFORM PROVIDE AMMONIA
TO SUPPORT TRACY
*
FUNDS WILL BE COMMITTED BY ISSUANCE OF
RELEASE ORDER NUMBERS AGAINST THE BPO
*
THE TERMS AND CONDITIONS OF THE CONTRACT
WITH BHE CONTRACT FULLY SIGNED AND
EXECUTED ON 3/26/2020
APPLY TO THIS BPO
*

PURCHASE ORDER

Sierra Pacific Power Company (dba NV Energy)

Send Invoice To:
NV Energy, Accounts Payable
PO BOX 10100
RENO, NV 89520-0024
Email to: APinvoice@nvenergy.com

Purchase Order : **00203672R00034**
Revision : **Release :** 00034
Date Printed : 11/30/20
Page Number : 2

Fac	Standard Name	Type	Description	Last Revised
	INV-INSTR	V	INVOICING INSTRUCTIONS	03/21/17

Line	Qty	UP	Catalog ID	Unit Price	Extension	
0001	46,640	LB	0000109113	$.077600	$3,619.26	**TAXABLE**

Qty: 46,640 **Delivery Date:** 12/05/20

Description:
AMMONIUM HYDROXIDE, SOLUTION, AMMONIA, REAGENT GRADE, 19%, BULK, 48,000 LB=APPRO
X 6000 GL, CAS #1336-21-6 MSDS
AMMONIUM HYDROXIDE, SOLUTION, 19%
BULK, REAGENT GRADE, MSDS REQD
BPO AIRGAS SPECIALTY BPO 121631

Mfr/Vendor : AIRGAS
Model :
Part : CBLKSCN19

Mfr/Vendor : HILL BROTHERS CHEMICAL CO
Model :
Part : AQUA AMMONIA 19%

Mfr/Vendor : AIRGAS SPECIALTY PRODUCTS
Model :
Part : CBLKSCN19

Purchase Order Total Amount

TOTAL THIS PO: $3,619.26

*** ***End of Purchase Order*** ***

Variable Terms and Conditions

Line **Standard Name** **Variable Text**

INV-INSTR INVOICING INSTRUCTIONS

A. Counterparty will submit to Company an invoice for payment and any supporting back-up documentation, such invoice will contain the following information:

1. A valid NV Energy purchase order (PO) number - including the leading

Attachment G

Price Schedule for Aqueous Ammonia Solution Various Suppliers/NVE Sites

Exhibit - Price Schedule for Aqueous Ammonia Solution Various Suppliers/NVE Sites

Supplier	Description	Delivery Locations	Ship Point	Delivery Unit of Measure	Total Price with Shipping per Pound	Total Price $/gal (19% equiv.)
Bulk Price 19% solution (~6000 gal load) Quotes specificly for Tracy Generating Station						
Supplier A	Ammonia Hydroxide, Solution, Ammonia, Reagent Grade, 19% Bulk	Tracy Sparks, NV 89434	Location A (Calif.)	48,000 pounds	$ 0.0776	$0.61
Supplier B	Ammonia Hydroxide, Solution, Ammonia, Reagent Grade, 19% Bulk	Tracy Sparks, NV 89434	Location B (Utah)	48,000 pounds	$ 0.1234	$0.97
Bulk Price 19% solution (~6000 gal load) Quotes for other facilities						
Supplier A	Ammonia Hydroxide, Solution, Ammonia, Reagent Grade, 19% Bulk	Chuck Lenzie Las Vegas, NV 89165	Loc. D (Calif.)	48,000 pounds	$ 0.0856	$0.67
Supplier B	Ammonia Hydroxide, Solution, Ammonia, Reagent Grade, 19% Bulk	Chuck Lenzie Las Vegas, NV 89165	Loc. B (Utah)	48,000 pounds	$ 0.1350	$1.06
Mini-Bulk Price 19% solution (~ 500 gallon load)						
Supplier A	Ammonia Hydroxide, Solution, Ammonia, Reagent Grade, 19%, Mini Bulk	Las Vegas Gen North Las Vegas, NV 89030	Loc. D (Calif.)	500 gallons	$ 0.3404	$2.67
Supplier B	Ammonia Hydroxide, Solution, Ammonia, Reagent Grade, 19%, Mini Bulk	Las Vegas Gen North Las Vegas, NV 89030	Loc. F (Nevada)	500 gallons	$ 1.0900	$8.54

Attachment H

Bureau of Labor Statistics

https://data.bls.gov/oes/#/home

Web page showing selections to obtain average labor rate for pipefitters and steamfitters nationally.

U.S. BUREAU OF LABOR STATISTICS

Occupational Employment Statistics Query System

OES

Occupational Employment Statistics

(For more information or help)

One occupation for multiple geographical areas

Select a search type

- ○ Multiple occupations for one geographical area
- ● One occupation for multiple geographical areas
- ○ Multiple occupations for one industry
- ○ One occupation for multiple industries

Select one occupation

Insulation Workers
Insulation Workers, Floor, Ceiling, and Wall
Insulation Workers, Mechanical
Painters and Paperhangers
Painters, Construction and Maintenance
Paperhangers
Pipelayers, Plumbers, Pipefitters, and Steamfitters
Pipelayers
Plumbers, Pipefitters, and Steamfitters
Plasterers and Stucco Masons

Select a geographic type

● National ○ State ○ Metropolitan or Non Metropolitan Area

Select one or more datatypes

(For printer-friendly HTML output, select a maximum of eight datatypes at a time.)

All data types
Employment
Employment percent relative standard error
Hourly mean wage
Annual mean wage
Wage percent relative standard error
Hourly 10th percentile wage
Hourly 25th percentile wage
Hourly median wage
Hourly 75th percentile wage

Next

Select one or more release dates

May 2019

Select an output type

HTML
Excel

Submit

U.S. BUREAU OF LABOR STATISTICS Division of Occupational Employment Statistics PSB Suite 2135 2 Massachusetts Avenue NE Washington, DC 20212-0001

Telephone:1-202-691-6569 www.bls.gov/OES Contact OES

Average Labor Rate Nationally for pipefitters and steamfitters

U.S. BUREAU OF LABOR STATISTICS

Occupational Employment Statistics Query System

OES

Occupational Employment Statistics

(For more information or help)

One occupation for multiple geographical areas

Back to Inputs

Occupation: Plumbers, Pipefitters, and Steamfitters(SOC code 472152)
Period: May 2019

Area name		Hourly median wage
National(0000000)		26.52

Footnotes:

SOC code: Standard Occupational Classification code -- see http://www.bls.gov/soc/home.htm

Data extracted on December 31, 2020

Web page showing selections to obtain average labor rate for pipefitters and steamfitters in Reno

U.S. BUREAU OF LABOR STATISTICS

Occupational Employment Statistics Query System

OES

Occupational Employment Statistics

(For more information or help)

One occupation for multiple geographical areas

Select a search type

- ( ) Multiple occupations for one geographical area
- (•) One occupation for multiple geographical areas
- ( ) Multiple occupations for one industry
- ( ) One occupation for multiple industries

Select one occupation

Insulation Workers
Insulation Workers, Floor, Ceiling, and Wall
Insulation Workers, Mechanical
Painters and Paperhangers
Painters, Construction and Maintenance
Paperhangers
Pipelayers, Plumbers, Pipefitters, and Steamfitters
Pipelayers
Plumbers, Pipefitters, and Steamfitters
Plasterers and Stucco Masons

Select a geographic type

( ) National ( ) State ( ) Metropolitan or Non Metropolitan Area

Select one or more areas

East-Central Montana nonmetropolitan area
Southwest Montana nonmetropolitan area
Nebraska
Omaha-Council Bluffs, NE-IA
South Nebraska nonmetropolitan area
Nevada
Las Vegas-Henderson-Paradise, NV
Nevada nonmetropolitan area
Reno, NV
New Hampshire

Next

Select one or more datatypes

(For printer-friendly HTML output, select a maximum of eight datatypes at a time.)

All data types
Employment
Employment percent relative standard error
Hourly mean wage
Annual mean wage
Wage percent relative standard error
Hourly 10th percentile wage
Hourly 25th percentile wage
Hourly median wage
Hourly 75th percentile wage

Next

Select one or more release dates

May 2019

Select an output type

HTML
Excel

Submit

U.S. BUREAU OF LABOR STATISTICS

Average Labor Rate in Reno for pipefitters and steamfitters

Occupational Employment Statistics Query System

OES

Occupational Employment Statistics

(For more information or help)

One occupation for multiple geographical areas

Back to Inputs

Occupation: Plumbers, Pipefitters, and Steamfitters(SOC code 472152)
Period: May 2019

Area name		Hourly median wage
Reno, NV(0039900)		30.05
Footnotes:		
SOC code: Standard Occupational Classification code -- see http://www.bls.gov/soc/home.htm Data extracted on December 31, 2020		

Attachment I

Revenue Requirement Percentage for SPPC

September 24, 2019

Ms. Trisha Osborne, Assistant Commission Secretary
Public Utilities Commission of Nevada
Capitol Plaza
1150 East William Street
Carson City, Nevada 89701-3109

RE: Sierra Pacific Power Company d/b/a NV Energy's Application addressing its annual revenue requirement for general rates charged to all classes of electric customers, in Docket No. 19-06002

Dear Ms. Osborne:

Sierra Pacific Power Company d/b/a NV Energy ("Sierra") hereby submit for filing the enclosed fully executed Stipulation in the above-referenced docket. The Stipulation constitutes a negotiated settlement which is entered into for the purpose of resolving the cost of capital (Phase I) and revenue requirement (Phase II) phases of the docket.

Should you have any questions regarding this filing, please contact me at 775-834-5692 or mgreene@nvenergy.com.

Sincerely,

/s/ Michael Greene
Michael Greene
Deputy General Counsel

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

In the matter of the Application by **SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY**, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers.)))) /	Docket No. 19-06002

PHASES I AND II STIPULATION

Sierra Pacific Power Company d/b/a NV Energy ("Sierra" the "Company") enters into this Stipulation with the Regulatory Operations Staff ("Staff") of the Public Utilities Commission of Nevada ("Commission"), the Office of the Attorney General, Bureau of Consumer Protection ("BCP"), Caesars Enterprise Services, LLC ("Caesars"); Eldorado Resorts LLC, Circus and Eldorado Joint Venture LLC d/b/a the Silver Legacy Resort Casino Reno, CC-Reno LLC, Montbleu Resort Casino & Spa (collectively "Eldorado") and the Truckee Meadows Water Authority ("TMWA," together "Eldorado & TMWA"); EP Minerals, LLC, Heavenly Valley, Limited Partnership, Nevada Cement Company, Nugget Sparks, LLC dba Nugget Casino Resort, Premier Magnesia, LLC, The Ridge Tahoe Property Owners' Association, Prime Healthcare Services-Reno, LLC dba Saint Mary's Regional Medical Center, Inc., Renown Health and Newmont USA Limited, ("NNIEU"); Nevada Gold Mines LLC ("NGM"); and Walmart, Inc. ("Walmart"). This Stipulation refers to the Company, Staff, BCP, Caesars, Eldorado, & TMWA, NNIEU, NGM, and Walmart as the "Signatories" and is intended to resolve the cost of capital (Phase I) and revenue requirement (Phase II) phases in Docket No. 19-06002 ("Docket").

Switch, Ltd. ("Switch") participated in all settlement negotiation, was provided a copy of this Stipulation, had the opportunity to review the Stipulation, and provide any comments or issues with the Stipulation. Based upon its review, Switch agrees that it will not oppose the Stipulation and will not seek to admit into the record pre-filed Phase I testimony or file Phase II testimony. Switch will file with the Commission a separate notice of non-opposition to the stipulation.

The Signatories agree that this Stipulation provides for a reasonable resolution of Phase I and Phase II of the Docket and that its approval is in the public interest. The Signatories jointly recommend that the Commission approve the Stipulation.

SUMMARY OF THE STIPULATION

The proposed resolution of the phases I and II of the Docket, as provided for in this Stipulation, is in the public interest. As a result of their investigations, the Signatories were able to reach an agreement to reduce Sierra's annual electric base tariff general revenue requirement by **$5 million**. The signatories agree that the stated return on equity for Sierra's electric operations will be set at 9.5 percent and any earnings in excess of 9.7 percent shall be shared equally (50/50) between Sierra and Sierra's Customers. The overall cost of capital will be set at 6.75 percent. This settlement does not affect the Rate Design phase of the Docket. The Signatories are free to argue Rate Design related issues, including weather normalization, in that phase of this Docket.

In summary, the Signatories jointly recommend that the Commission approve the Stipulation as being in the public interest. The Stipulation provides for a reasonable outcome of the matters addressed.

RECITALS

A. Whereas, on June 3, 2019, Sierra filed an application with the Commission pursuant to Nevada Revised Statutes ("NRS") § 704.110(3) and (4), addressing its annual revenue requirement for general rates charged to all classes of electric customers. The Commission designated the proceeding as Docket No. 19-06002.

B. Whereas, pursuant to NRS §§ 703.301 and 228.360, Staff and the BCP participate in the Docket by right.

C. The following parties' petitions for leave to intervene in the Dockets were granted: Walmart, NNIEU; Caesars; Eldorado, TMWA; NGM[1] and Switch.

[1] The Commission transferred Newmont USA, LTD., d/b/a Newmont Goldcorp Corporation and Newmont Nevada Energy Investment LLC's intervention to Nevada Gold Mines, LLC on September 12, 2019.

D. Whereas, the Signatories have reviewed the application, including the prepared direct and certification testimony filed by Sierra, Sierra's responses to the discovery requests submitted in the Docket and the prepared direct testimony filed by Staff, BCP, NGM, Walmart and Switch.

E. Whereas, the Signatories desire to resolve the cost of capital and revenue requirement related issues raised in the application.

NOW THEREFORE, in light of the foregoing recitals and in consideration of the promises set forth below, the Signatories agree as follows:

AGREEMENT

Revenue Requirement and Cost of Capital

1. The Signatories agree it is to the benefit of Sierra's electric customers to implement a $5 million reduction in Sierra's annual revenue requirement for electric operations.

2. Sierra's electric operations return on equity shall be 9.5 percent.

3. Any earnings in excess of 9.7 percent shall be shared equally (50/50) between Sierra and Sierra's customers in the same manner as is currently tracked and reported in annual deferred energy dockets and credited to customers in subsequent general rate cases for Nevada Power Company, d/b/a/ NV Energy.

4. Sierra's rate of return shall be based on the capital structure set forth in Statement F of Sierra's certification filing, with the embedded cost of debt reduced by two basis points.[2] The adjusted and agreed rate of return shall be 6.75 percent as set forth in the table below:

[2] Identified in Sierra's response to Data Request Staff 129.

Description	Capital Amount	Capital Ratio	Cost of Capital	Weighted Cost of Capital
Debt				
Short-Term Debt	$ -	0.00%	0.00%	0.00%
Customer Deposits (1)	18,847	0.83%	2.50%	0.02%
Long-Term Debt	1,100,305	48.25%	3.91%	1.89%
Total Debt	$ 1,119,152	49.08%	3.89%	1.91%
Equity				
Preferred Equity	$ -	0.00%	0.00%	0.00%
Common Equity (2)	1,161,151	50.92%	9.50%	4.84%
Total Equity	$ 1,161,151	50.92%	9.50%	4.84%
Total Capital	$ 2,280,303	100.0%		6.75%

Rate base and Operation and Maintenance Expense Adjustments

5. For purposes of reaching a negotiated settlement in this Docket, the Signatories agree that Sierra will remove carrying charges from the 2016 and 2018 integrated resource plan (IRP) regulatory asset rate base balances as certified. The amortization of three years will remain the same.

6. For purposes of reaching a negotiated settlement in this Docket, the Signatories agree that Sierra will remove carrying charges from general rate case (GRC) 2016 regulatory asset rate base balance as certified. The amortization of three years will remain the same.

7. The Signatories agree that this Stipulation does not preclude the Company from requesting to apply carrying charges on future IRP or GRC regulatory assets, nor does it limit the Signatories right to contest such future application.

8. Sierra agrees to work with Staff and BCP to review and reclassify any Nevada Power related costs from the 2016 and 2018 IRP that were inadvertently included in this docket for consideration in the Nevada Power rate case, and will adjust the certification balances included in rate base and the annual amortization.

9. Sierra will utilize the fourth quarter scorecard for purposes of the Short Term Incentive Plan calculation in this case and adjust operations and maintenance expense accordingly.

10. The Signatories agree that the unprotected excess Accumulated Deferred Income Tax regulatory liability will be amortized over a period of six years, as proposed in the filing.

11. When calculating electric revenue requirement for purposes of this case, Sierra will make a one-time operations and maintenance adjustment of $3.850 million.

Other Adjustments

12. Sierra agrees to review its asset capitalization policy prior to the next GRC filing.

13. Sierra agrees to review its travel and entertainment policy prior to the next GRC filing.

14. This settlement does not address Sierra's cash working capital methodology, nor does it address the Signatories' disagreement regarding said methodology. This issue will be addressed in a future Docket.

15. For Generally Accepted Accounting Principles or "GAAP" and regulatory accounting purposes, Sierra will only make the adjustments specified in the Stipulation. Thus, for the purpose of GAAP and regulatory accounting purposes the applications shall be deemed approved as filed except as modified in this Stipulation.

Phases I and II procedural Schedule

16. The Signatories agree and recommend that the Commission suspend the existing procedural schedule as set forth in Procedural Order No. 1, and request that the Commission schedule a hearing as soon as possible for the presentation of the Stipulation to the Commission.

Phase III (Rate Design)

17. The Signatories agree and recommend that the Commission adopt the following procedural schedule for Phase III of the Docket:

a. October 8, 2019 Staff, BCP, and Intervener Phase III testimony[3]

[3] No change from current procedural schedule.

b. October 18, 2019 Staff, BCP, and Intervener Phase III rebuttal testimony[4]

c. October 28, 2019 Sierra Rebuttal testimony

d. November 4, 2019 Phase III hearing commencement

General Provisions

18. Except as expressly set forth above, the Stipulation shall not serve as precedent for the resolution of any issue in the future by the Commission.

19. This Stipulation is entered into for the purpose of resolving the cost of capital and revenue requirement phases of the Docket. This Stipulation is made upon the express understanding that it constitutes a negotiated settlement. The provisions of this Stipulation are not severable.

20. In accordance with Nevada Administrative Code § 703.845, this Stipulation settles only issues relating to the present proceedings and seeks relief that the Commission is empowered to grant.

21. Each Signatory, by signing this Stipulation, acknowledges that except as otherwise modified above, the requests contained in the Docket will be deemed approved as filed.

22. Each Signatory, by signing this Stipulation, acknowledges that the Stipulation will result in just and reasonable rates as a result of the agreed upon revenue requirement settlement, and provides Sierra a reasonable opportunity to earn its authorized rate of return.

23. This Stipulation represents a compromise of the positions of the Signatories. As such, conduct, statements and documents disclosed in the negotiation of this stipulation shall not be admissible as evidence in these or any other proceeding. Except as set forth herein, neither this Stipulation, nor its terms, nor the Commission's acceptance or rejection of the terms contained in this Stipulation shall have any precedential effect in future proceedings.

24. This Stipulation may be executed in one or more counterparts, all of which together shall constitute the original executed document. This Stipulation may be executed

[4] The dates outlined in paragraph 17 (b)-(d) are the suggested dates of the Signatories, if dates following these work better for the Commission, the Signatories will make those later dates work, and ask that whatever additional time is allotted be split equally between the remaining deadlines.

by signatories by electronic transmission, which signatures shall be as binding and effective as original signatures.

Signatures on following page*

This Stipulation is entered into by each Signatory as of the date entered below:

	SIERRA PACIFIC POWER COMPANY d/b/a NV Energy
9/24/19 Date	By: Michael Greene, Esq. Deputy General Counsel
	REGULATORY OPERATIONS STAFF OF THE PUBLIC UTILITIES COMMISSION OF NEVADA
Date	By: Samuel S. Crano, Esq. Assistant Staff Counsel
	BUREAU OF CONSUMER PROTECTION
Date	By: Michael Saunders, Esq. Senior Deputy Attorney General
	CAESARS ENTERPRISE SERVICES, LLC
Date	By: Fred Schmidt, Esq. Jaclyn Calicchio, Esq.

This Stipulation is entered into by each Signatory as of the date entered below:

SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy

____
Date

____
By: Michael Greene, Esq.
Deputy General Counsel

REGULATORY OPERATIONS STAFF OF THE PUBLIC UTILITIES COMMISSION OF NEVADA

9-24-19
Date

By: Samuel S. Crano, Esq.
Assistant Staff Counsel

BUREAU OF CONSUMER PROTECTION

9-24-19
Date

By: Michael Saunders, Esq.
Senior Deputy Attorney General

CAESARS ENTERPRISE SERVICES, LLC

____
Date

____
By: Fred Schmidt, Esq.
Jaclyn Calicchio, Esq.

This Stipulation is entered into by each Signatory as of the date entered below:

SIERRA PACIFIC POWER COMPANY
d/b/a NV Energy

Date

By: Michael Greene, Esq.
Deputy General Counsel

REGULATORY OPERATIONS STAFF OF THE PUBLIC UTILITIES COMMISSION OF NEVADA

Date

By: Samuel S. Crano, Esq.
Assistant Staff Counsel

BUREAU OF CONSUMER PROTECTION

Date

By: Michael Saunders, Esq.
Senior Deputy Attorney General

CAESARS ENTERPRISE SERVICES, LLC

9-24-19

Date

Fred Schmidt

By: Fred Schmidt, Esq.
Jaclyn Calicchio, Esq.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

ELDORADO RESORTS LLC, CIRCUS AND ELDORADO JOINT VENTURE LLC D/B/A THE SILVER LEGACY RESORT CASINO RENO, CC-RENO LLC, MONTBLEU RESORT CASINO & SPA AND THE TRUCKEE MEADOWS WATER AUTHORITY

Date	By: Lucas Foletta, Esq.

EP MINERALS, LLC, HEAVENLY VALLEY, LIMITED PARTNERSHIP, NEVADA CEMENT COMPANY, NUGGET SPARKS, LLC DBA NUGGET CASINO RESORT, PREMIER MAGNESIA, LLC, THE RIDGE TAHOE PROPERTY OWNERS' ASSOCIATION, PRIME HEALTHCARE SERVICES-RENO, LLC DBA SAINT MARY'S REGIONAL MEDICAL CENTER, INC., RENOWN HEALTH AND NEWMONT USA LIMITED

Date	By: Karen Peterson, Esq.

NEVADA GOLD MINES LLC and WALMART INC.

Date	By: Vicki M. Baldwin, Esq.

ELDORADO RESORTS LLC, CIRCUS AND ELDORADO JOINT VENTURE LLC D/B/A THE SILVER LEGACY RESORT CASINO RENO, CC-RENO LLC, MONTBLEU RESORT CASINO & SPA AND THE TRUCKEE MEADOWS WATER AUTHORITY

Date

By: Lucas Foletta, Esq.

EP MINERALS, LLC, HEAVENLY VALLEY, LIMITED PARTNERSHIP, NEVADA CEMENT COMPANY, NUGGET SPARKS, LLC DBA NUGGET CASINO RESORT, PREMIER MAGNESIA, LLC, THE RIDGE TAHOE PROPERTY OWNERS' ASSOCIATION, PRIME HEALTHCARE SERVICES-RENO, LLC DBA SAINT MARY'S REGIONAL MEDICAL CENTER, INC., RENOWN HEALTH AND NEWMONT USA LIMITED

Sept. 24, 2019
Date

for
By: Karen Peterson, Esq.

NEVADA GOLD MINES LLC and WALMART INC.

Date

By: Vicki M. Baldwin, Esq.

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

ELDORADO RESORTS LLC, CIRCUS AND ELDORADO JOINT VENTURE LLC D/B/A THE SILVER LEGACY RESORT CASINO RENO, CC-RENO LLC, MONTBLEU RESORT CASINO & SPA AND THE TRUCKEE MEADOWS WATER AUTHORITY

______________________________ ______________________________
Date By: Lucas Foletta, Esq.

EP MINERALS, LLC, HEAVENLY VALLEY, LIMITED PARTNERSHIP, NEVADA CEMENT COMPANY, NUGGET SPARKS, LLC DBA NUGGET CASINO RESORT, PREMIER MAGNESIA, LLC, THE RIDGE TAHOE PROPERTY OWNERS' ASSOCIATION, PRIME HEALTHCARE SERVICES-RENO, LLC DBA SAINT MARY'S REGIONAL MEDICAL CENTER, INC., RENOWN HEALTH AND NEWMONT USA LIMITED

______________________________ ______________________________
Date By: Karen Peterson, Esq.

NEVADA GOLD MINES LLC and WALMART INC.

______________________________ ______________________________
Date By: Vicki M. Baldwin, Esq.

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing filing of **SIERRA PACIFIC POWER COMPANY D/B/A/ NV ENERGY** in Docket No. 19-06002 upon the persons listed below by the following:

Tammy Cordova
Public Utilities Comm. of Nevada
1150 E. William Street
Carson City, NV 89701-3109
tcordova@puc.nv.gov

Staff Counsel Division
Public Utilities Comm. of Nevada
9075 West Diablo, Suite 250
Las Vegas, NV 89148
pucn.sc@puc.nv.gov

Bureau of Consumer Protection
100 N. Carson St.
Carson City, NV 89701
bcpserv@ag.nv.gov

Michael Saunders
Bureau of Consumer Protection
8945 W. Russell Road, Suite 204
Las Vegas, NV 89148
msaunders@ag.nv.gov
bcpserv@ag.nv.gov

Fred Schmidt (Caesars)
Jaclyn M. Calicchio
Holland & Hart LLP
377 South Nevada Street
Carson City, NV 89703
fschmidt@hollandhart.com
jmcalicchio@hollandhart.com

Eric Dominguez (Caesars)
Caesars Enterprise Services, LLC
One Caesars Palace Drive
Las Vegas, NV 89109
edominguez@caesars.com

Gavin Jangard (Newmont)
John Seeliger
Newmont USA LTD
914 Dunphy Ranch Rd
Battle Mountain, NV 89820
Gavin.jangard@newmont.com
John.seeliger@newmont.com

Lucas Foletta, Esq. (Eldorado and TMWA)
Andrea Black
McDonald Carano LLP
100 W. Liberty St., 10th Fl
Reno, NV 89501
lfoletta@mcdonaldcarano.com
ablack@mcdonaldcarano.com

Robert D. Sweetin, Esq. (Switch)
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ginge@kinectenergy.com

Karen A. Peterson, Esq. (NNIEU)
Justin M. Townsend, Esq.
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jtownsend@allisonmackenzie.com

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vbaldwin@parsonsbehle.com

Steve W. Chriss (Walmart)
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Bentonville, Arkansas 72716
Stephen.Chriss@walmart.com

Vicki M. Baldwin (NGM/Newmont)
Parsons Behle & Latimer
201 South Main Street, Ste. 1800
Salt Lake City, Utah 84111
vbaldwin@parsonsbehle.com

DATED this 24th day of September, 2019.

/s/Lori Petersen
Lori Petersen
Senior Legal Administrative Assistant
Sierra Pacific Power Company

Nevada Power Company
and Sierra Pacific Power Company
d/b/a NV Energy

Appendix B.5.e - Response Letter 3

NV Energy

April 16, 2021

Steven McNeece
Nevada Department of Environmental Protection
901 S. Stewart Street
Suite 4001
Reno, NV 89701

Re: 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

Mr. McNeece:

Per your email correspondence dated March 11, 2021, Nevada Power Company d/b/a NV Energy (NVE) hereby provides a response detailing Nevada Division of Environmental Protection (NDEP)'s most recent request for additional information regarding the Four Factor Analyses at both the Tracy and North Valmy Generating Stations previously submitted March 13, 2020. Please note that this is the response to NDEP's third follow-up request for additional information, as NVE also provided a previous response to NDEP's first request for additional information in a letter dated July 8, 2020, as well as a second request for additional information in a letter dated January 15, 2021. This letter and attachments address NDEP's most recent questions and should be considered a third addendum to the previously submitted Four Factor Analyses.

NVE appreciates the opportunity to work with NDEP in this endeavor. Please feel free to contact Sean Spitzer at (702) 402-5132 should you have any questions.

Sincerely,

Starla Lacy

Starla Lacy
Vice President, Environmental Services, Safety, and Land Management
NV Energy

Response to NDEP's Additional Questions North Valmy and Tracy Generating Station's Four Factor Analyses

North Valmy Generating Station Responses:

Question (a) **<u>Dry Sorbent Injection (DSI) Evaluation</u>**

Q(a)(1) *Please evaluate Dry Sorbent Injection for both Valmy Unit 1 and Valmy Unit 2.*

A(a)(1) As explained in our letter dated January 15, 2021 responding to the questions received from NDEP in November 2020, NVE recognizes that DSI is a technically feasible means to control acid gas emissions like sulfur dioxide (SO2) from coal-fired power plants like Valmy Unit 1 and Unit 2.

DSI is already in use on Valmy Unit 1 but the system that is installed on this unit was designed to control HCl emissions, not SO2 emissions. As described further below, the DSI system currently in use cannot be adapted to utilize the sorbents that would be required in order to control SO2 emissions; the existing system would therefore need to be replaced. In our previous response, we described how the installation of DSI on North Valmy Unit 1 to control SO2 emissions would entail a total capital cost of $37,421,000, a total annualized cost impact of $6,702,000 per year, and a cost effectiveness of over $7,500 per ton controlled.

Accordingly, NV Energy does not consider replacing the existing DSI system on Unit 1 with a system designed to control SO2 emissions to represent a cost-effective alternative.

Valmy Unit 2 utilizes a lime-based flue gas desulfurization (FGD) system to control SO2 emissions and does not utilize DSI. NDEP previously provided copies of two other Four Factor Analyses for other electric generating stations that addressed DSI as an SO2 emissions control alternative[1,2]. Each of these studies included an evaluation of DSI operating in conjunction with and to improve the SO2 control efficiency of an existing flue gas desulfurization (FGD) system. Both studies concluded that the use of DSI in this manner was inferior to other alternatives to reduce SO2 emissions. Each study noted that for several reasons, the use of sodium-based sorbents (such as sodium bisulfite, trona, or soda ash) would be potentially problematic to augment the performance of an existing lime-based FGD system. Potential issues identified include the potential for additional corrosion, adverse effects on the characteristics of byproduct solids generated by the FGD system, and possible formation of a brown plume. These studies concluded that using hydrated lime as the sorbent was more suitable when using DSI in conjunction with existing lime-based FGD systems.

In the Four Factor Analysis for the Antelope Valley Station in North Dakota, however, it was concluded that the use of DSI in conjunction with the existing FGD would not provide any additional removal than what could already be achieved by increasing the fresh lime makeup or calcium content to the existing FGD system. In our previous submittal, we explained the upgrades that have been made to the FGD system on Valmy Unit 2. The system's current performance (approximately 80% based on 2020 operating data) has already been optimized to the extent practicable with respect to the calcium/sulfur

[1] "North Dakota Round II Regional Haze State Implementation Plan Determination's Four-Factor Analysis for Antelope Valey Station Units 1 and 2," Sargent & Lundy, LLC January 30, 2019.
[2] "Coyote Station Unit 1: North Dakota Regional Haze Second Planning Period Four-Factor Analysis," Sargent & Lundy, LLC May 8, 2019.

ratio employed. In particular, as noted in our original Four Factor Analysis for the North Valmy Station, the disposal of waste solids associated with the Unit 2 FGD system must conform to the recent amendments to EPA's regulations for disposal of coal combustion residuals (CCR). Further increase in the calcium/sulfur ratio beyond that currently employed would have negative implications with respect to conformance with these CCR disposal requirements. Therefore, we do not consider it feasible to further improve the system performance via the use of a DSI system upstream of the existing FGD.

Q(a)(2) *The EPA Control Cost Manual (CCM) recommends against using studies that are more than 5 years old. If the 2012 S&L study will be the basis for these analyses, make the necessary updates/confirmations to reflect a 2020/2021 analysis.*

A(a)(2) The principal source of the technical and cost information about DSI presented in a previous response dated January 15, 2021 was a study conducted by Sargent & Lundy (S&L) in 2012 regarding the feasibility of utilizing this technology on North Valmy Unit 1 to comply with the electric utility Mercury and Air Toxics Standards (MATS) rule. Per NDEP's request, a copy of the S&L reports detailing the investigation of DSI for Valmy Unit 1, as well as S&L's SCR retrofit report, have been included as attachments to this response. The cost information we presented in our previous submittal was escalated from the 2012 basis used in the S&L DSI study to current dollars using Chemical Engineering Plant Cost Index values. The escalation methodology that we used is consistent with that described in Section 2.5.3 of the Seventh Edition of EPA's Control Cost Manual. This is the same methodology that EPA has used to estimate the current cost of emission control systems presented in other chapters of the Control Cost Manual.

Q(a)(3) *Did NVE install a different control instead of DSI for Unit 1 to comply with MATS?*

A(a)(3) NVE utilizes a DSI system employing hydrated lime on North Valmy Unit 1. As explained in our previous submittal, under the MATS rules utility generating plants are required to meet a numeric emission limit for HCl emissions as a surrogate for acid gas emissions. The existing DSI system on Unit 1 is used to ensure compliance with the MATS HCl limit, and hydrated lime was selected as the appropriate sorbent to use on Unit 1 because of its capability to selectively react with HCl.

However, the MATS rule also contains an alternate limit for SO2 for units equipped with FGD units, and the rule defines DSI as a type of dry FGD technology. The purpose of the S&L study was to assess whether DSI could be utilized on Valmy Unit 1 to meet the alternate SO2 limit rather than the HCl limit.

S&L determined that the DSI system on Unit 1 that was installed to meet the MATS HCl limit would not be suitable to meet the MATS SO2 limit. When DSI is employed, the acid flue gas constituents (including HCl and SO2) compete for utilization of the sorbent. The DSI sorbent that was selected to control HCl (hydrated lime) is less reactive to SO2 than with HCl and has not been proven capable of achieving the high SO2 removal efficiency that would be needed to meet the MATS SO2 limit. Two other DSI sorbents (sodium sesquicarbonate dihydrate, or trona, and sodium bicarbonate) have been shown to be more effective at SO2 control with DSI, and these other sorbents were the focus of the S&L study.

However, the existing sorbent handling system would need to be replaced in order to utilize either trona or sodium bicarbonate to control SO2 emissions via DSI on Unit 1. Additional sorbent preparation and handling equipment would be needed, as the existing system is not compatible with the use of either trona or sodium bicarbonate. Primary deficiencies include lack of an activated carbon storage and injection for brown plume control, or milling equipment for trona/sodium bicarbonate use. Milling to decrease the size of the sorbent particles improves the utilization of sorbent for SO2 control by increasing the sorbent surface area.

As noted above, replacement of the existing DSI system on Valmy Unit 1 with a DSI system to control SO_2 emissions is not considered to be cost effective.

Q(a)(4) *Formation of Brown Plume:*

- *What can be done to prevent the formation of a brown plume*
- *The unit has an existing LNB+OFA system to control NOx emissions; could this help prevent the formation of NO2?*
- *How low do controlled NOx concentrations have to be to prevent the formation of a brown plume for each unit?*
- *Would a brown plume due to the DSI system violate the requirements of Valmy's permit?*
- *Please consider the injection of activated carbon into the flue gas to reduce the brown plume.*

A(a)(4) The presence of a sufficient quantity of nitrogen dioxide (NO_2) in the plume from a power plant produces a yellow or brown colored plume.[3] Nearly all of the NOx emissions from combustion sources typically consist of nitric oxide (NO) and only a small quantity of NO_2. As explained in our previous submittal, when studying the feasibility of using DSI on Valmy Unit 1, S&L noted that the use of sodium-based sorbents in DSI systems has the potential to result in the formation of a brown plume because of the enhanced oxidation of NO to NO_2 when such sorbents are used. Accordingly, one of the principal means to prevent the formation of brown plumes is avoiding the use of sodium-based sorbents.

Traditional combustion-based NOx control systems such as air staging and the use of low NOx burners are of limited effectiveness in controlling brown plume formation because such systems simply reduce overall NOx formation. The existing LNB+OFA system on Valmy Unit 1 has been optimized to minimize NOx formation; further reduction in NOx in order to minimize brown plume formation should sodium-based DSI sorbents be used on this unit is not possible.

Yellow or brown plume formation can occur when combustion turbine-based power systems are started up because under startup or minimum load conditions a greater fraction of the NOx produced is NO_2 than under normal load conditions. One study of visible plume suppression methods found that NO_2 can become visible at a concentration of about 10 – 15 ppmv.[4] Another study of visible plume formation in jet engine exhaust concluded brown plume formation occurred at NO_2 concentrations greater than about 40 ppmv.[5]

During the field study to assess the feasibility of employing DSI to control SO_2 emissions on Valmy Unit 1, it was found that opacity readings in the Unit 1 stack increased by a factor of 10 when sodium-based DSI sorbents were tested. Consequently, NVE concluded that it would be more difficult to maintain

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[3] Latimer, D.A. and Samuelsel, G.S., "Visual Impact of Plumes from Power Plants: A Theoretical Model," Atmospheric Environment, V. 12, pp 1455-1465.
[4] Feitelberg, A.S. and Correa, S.M, "The Role of Carbon Monoxide in NO2 Plume Formation," Presented at the International Gas Turbine & Aeroengine Congress and Exhibition, Indianapolis, Indiana (1999).
[5] Seto, S.P. and Lyon, T.F., "Nitrogen Oxide Emissions Characteristics of Augmented Turbofan Engines," Presented at the International Gas Turbine & Aeroengine Congress and Exhibition, Cincinnati, Ohio (1993)

continuous compliance with the opacity limit on Unit 1 if the sodium-based sorbents needed to control SO2 emissions were employed.

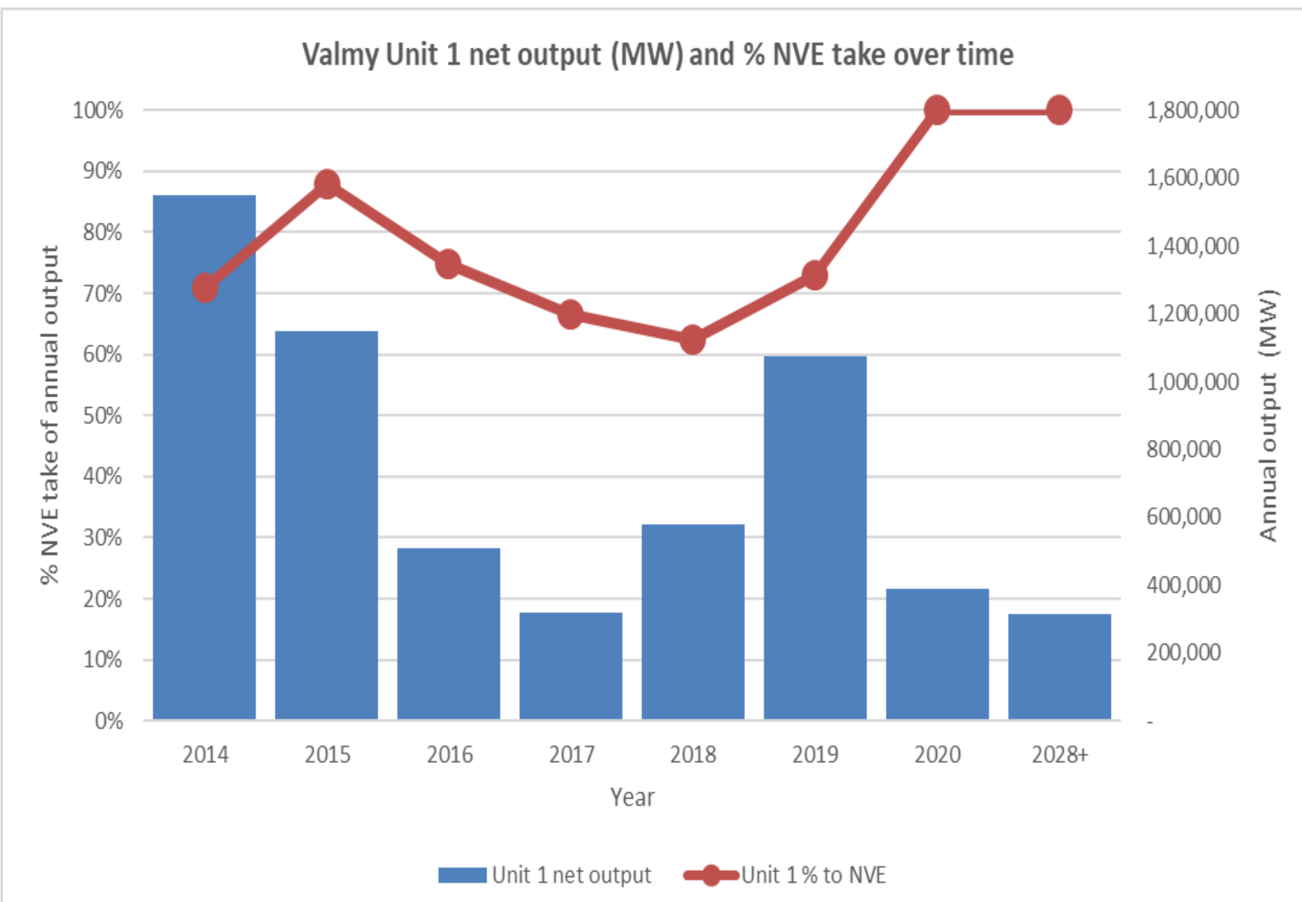
The S&L study on the use of DSI on Unit 1 recommended that activated carbon be injected in conjunction with the use of DSI for SO_2 control. The cost of including activated carbon injection equipment was therefore included in the estimated capital cost associated with this alternative that we provided with our previous response.

North Valmy Question (b) **<u>Increase of Utilization/Emissions in 2019 at Unit 1</u>**

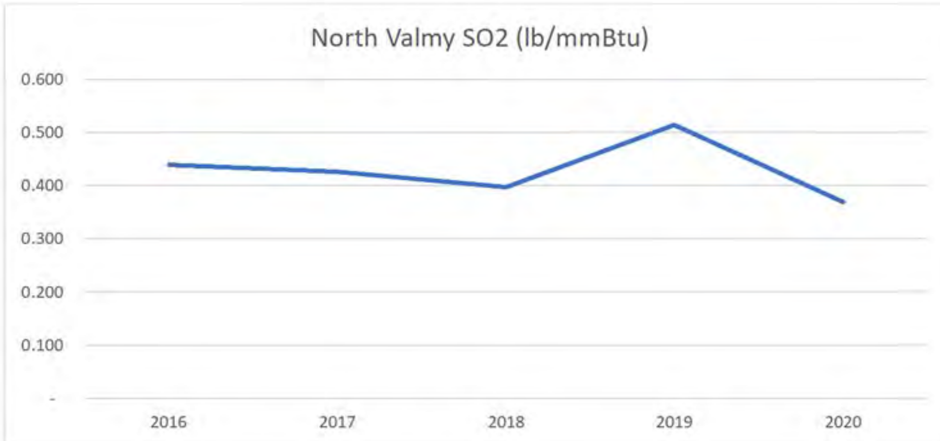
Q(b)(1) *The latest response also shows that 2019 output of Unit 1 wet up, however it also shows that most of the output was NVE's at 73% compared to 62% in the previous year.*

A(b)(1) In 2019 there was a slight increase in NVE's proportional take of the output from Unit 1 as compared to 2018 as NDEP has observed. However, a review of historical data shows that NVE's output take has typically fluctuated +/- 15% year over year. For example, the 2015 year shows a higher percentage of NVE take than in 2019, as shown on the chart below.

While many factors contribute to the reasons behind the year-over-year fluctuation in output take by NVE/IPC, the subject is now no longer relevant because Idaho Power completed their exit from their share of Unit 1's output on December 31, 2019. All of Unit 1's operation in 2020 was taken 100% by NVE, and all ensuing operation until the unit's eventual retirement will continue to be taken 100% by NVE.



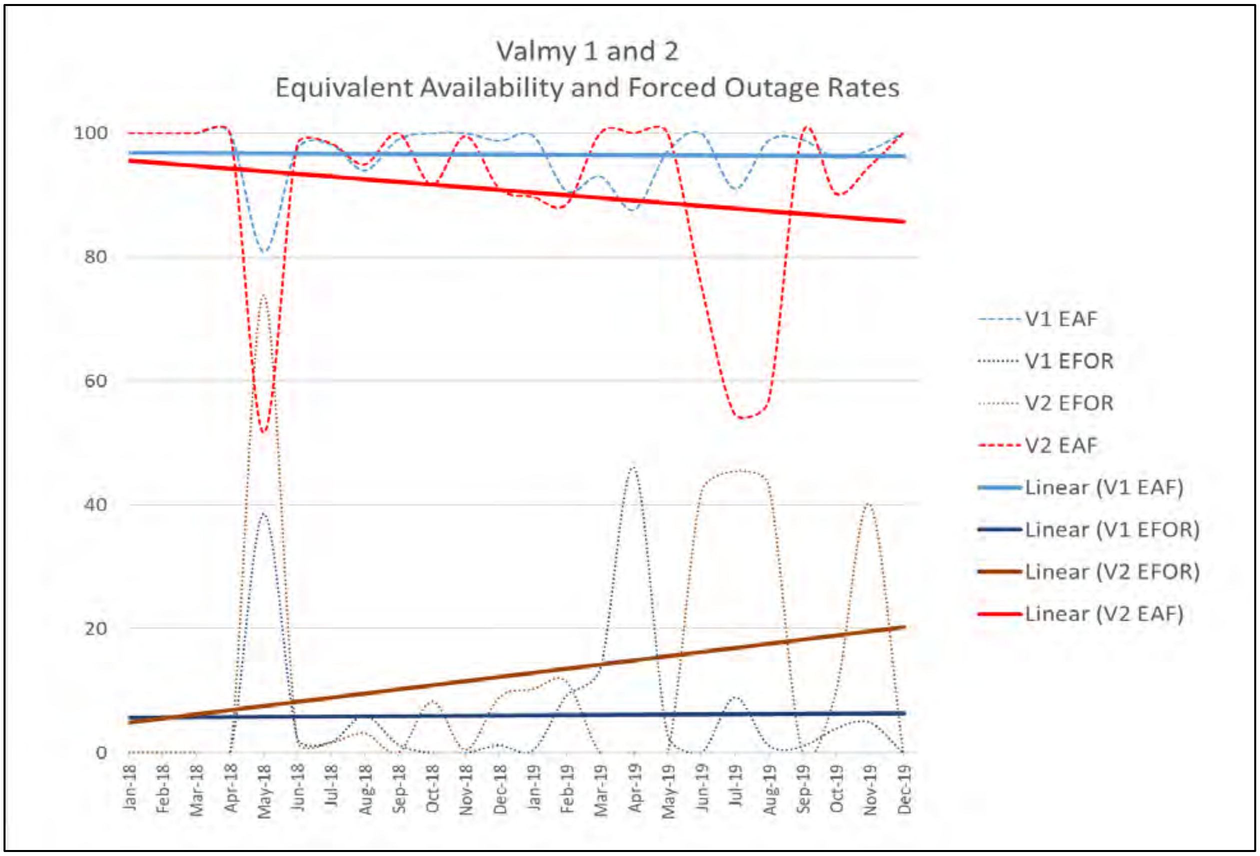
Q(b)(2) *The chart below shows that, not only did SO2 emissions increase due to increased utilization in 2019, but SO2 emissions also increased. A review of unit-specific capacity factors shows that load was shifted to the uncontrolled Unit 1 in 2019 instead of the controlled Unit 2. Why?*



A(b)(2) As described in a previous response to NDEP's questions in the report dated January 15, 2021, the North Valmy Station experienced an extended run during 2019 due to a combination of factors including the high gas prices in the northwest as well as transmission reliability in the region. While both units were in demand during the year, Unit 2 experienced significant loss of capacity primarily due to scrubber pluggage, pulverizer problems, and several other operational constraints.

To expand on the topic in more detail, NVE has developed a visual representation of North Valmy's equipment availability and forced outage over the 2018-2019 period in the chart on the following page using data from the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS), or NERC-GADS. The NERC-GADS data is a mandatory industry reporting program required for conventional generating units 20 MW and larger. The objective of the reporting program is to provide compilation and maintenance of an accurate, dependable, and comprehensive database capable of monitoring the performance of electric generating units and major pieces of equipment.

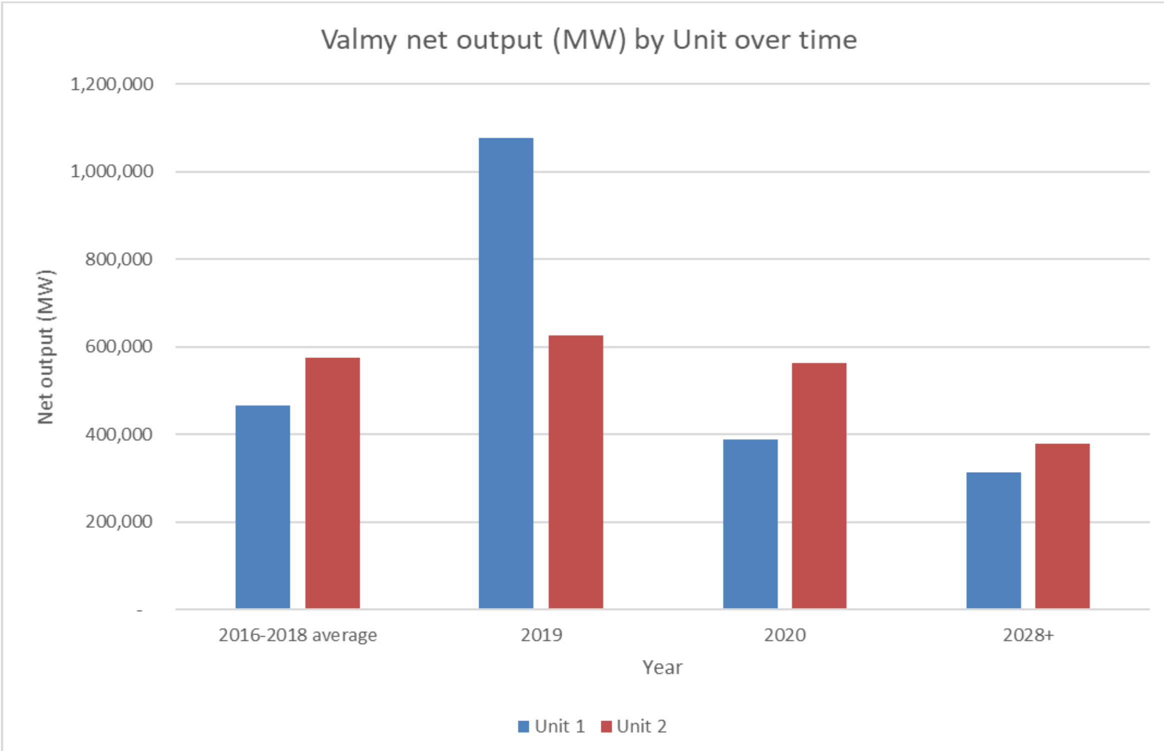
The chart shows the Equivalent Availability Factor (EAF) and the Equivalent Forced Outage Rates (EFOR) for Units 1 and 2 for this 2018-2019 period. EAF is the fraction of a given operating period in which a generating unit is available without any outages and equipment or seasonal deratings. EFOR is the hours of unit failure (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of the availability of that unit (unplanned outage, unplanned derated, and service hours).



In the chart above, note the solid light and dark blue trend lines showing a consistently very high EAF and a very low EFOR for Unit 1 over the time period. In contrast, note the solid red and brown trend lines for Unit 2 showing decreasing EAF and increasing EFOR throughout 2019. These data support the conclusion that, among other reasons already described, Unit 2's unavailability during periods of load demand in 2019 was a significant contributing factor as to why Unit 1 served a higher proportion of the station output during the year.

Q(b)(3) *The latest response states "The output of North Valmy Unit 1 was also higher in 2019 due to Idaho Power's exiting of their share of Unit 1's output – an action that necessitated the consumption of the coal reserves for Unit 1 that had previously been purchased by Idaho Power." If this is the reasoning for this, please provide more narrative and documentation for it. However, more explanation is needed as to why the uncontrolled unit was used more instead of the controlled unit (referring to NVE's portion only) and why it's unreasonable to anticipate the same occurrence in future years.*

A(b)(3) As discussed above as well as in previous responses, there were several factors that in combination led to Unit 1 operating more than Unit 2 during 2019. However, Unit 1's operation in 2019 in particular is an anomaly when compared against recent trends (2016-2018 baseline period); this distinction is further illustrated when compared against the most recently available operating data for year 2020, as displayed in the chart below.



Additionally, as explained in previous submittals, Idaho Power has completed the exit from their share of Unit 1 as of December 31, 2019. Accordingly, NVE is contractually bound to limit its utilization of Unit 1 by no more than half the full capacity of the unit. This limitation is currently in effect and will remain so until the unit is retired. Therefore, when anticipating Unit 1's future operation from a resource planning perspective, this limitation is expected to result in proportionally less operation of Unit 1 than Unit 2 in the future.

North Valmy Question (c) **Reported 2020 Emissions**

Q(c) *Please provide NOx and SO2 emissions at Valmy reported for 2020 and compare to the 2016-2018 baseline. Use this data to confirm that the current baseline reflects expected future emissions and that 2019 emissions do not reflect normal operations. This may support NVE's conclusion in the previous question as well.?*

A(c) The following table compares the actual 2020 NOx and SO2 emissions from North Valmy Units 1 and 2 to the corresponding emissions in the 2016-2018 baseline. Included in this table for comparison purposes are the projected emission rates from each unit in 2028.

		Baseline (ton/yr)	2020 (ton/yr)	2028 Projections[1] (ton/yr)
NOx Emissions	Unit 1	804	675	534
	Unit 2	1,002	928	665
SO2 Emissions	Unit 1	1,812	1,458	1,202
	Unit 2	501	461	332

[1]2028 projections assume the same heat rate/emission factors as in the baseline years as well as the same output excluding IPC's portion.

The data presented in this table, along with the charts shown above and explanations provided in the preceding responses, all confirm that operation of the North Valmy Station in 2019 is not reflective of normal operations of the station with respect to the selected baseline years, and that the emissions from 2019 are not reflective of expected future emissions from the station.

Tracy Generating Station Responses:

In addition to the updates related to the responses below, upon further analysis NVE has made one additional revision to the cost estimates for SCR installation on Piñon Pine. As discussed previously, in contrast to the capital cost estimations of SCR for a boiler, the EPA Cost Control Manual (CCM) does not specify cost estimation methodology for installing SCR on a combustion turbine. Therefore the capital cost for Tracy's Piñon Pine SCR installation was based on a budgetary proposal from a vendor, as well as a few ancillary costs. However, the standard practice by NVE and other regulated utilities for executing large capital projects is to utilize an Engineering, Procurement, and Construction (EPC) contractor to oversee and manage all aspects of these types of projects. The EPC contracts will specify liquidated damages to transfer risk to the contractor and also offer liability, warranty, and other assurances such as design and performance guarantees, which are essential for projects like SCR installation where performance and emission guarantees are necessary to comply with federally enforceable limits in the air permit. Given the increased liability of providing such guarantees and the responsibility for oversight of all project related work, EPC contractors may acquire additional insurance policies and charge a premium for these contract terms. EPA sponsored studies such as Sargent & Lundy's 2017 update to the IPM SCR cost model indicated that the costs of turnkey EPC contracts are higher than a separate lump-sum contracts approach[6]. EPA's own Retrofit Cost Analyzer (RCA) Excel-based tool (which has a boiler SCR cost methodology) adds 15% to the overall project cost if an EPC contract is to be used[7]. Therefore, we are providing updated cost analyses that include a 15% EPC adjustment to the capital cost of SCR installation on Tracy's Pinion Piñon Pine. We believe this is a more accurate estimate of the expected costs, but have also included in Attachment C the costs without this EPC adjustment.

Question (a) <u>Baseline Emissions</u>

Q(a) *Newly reported 2019 and 2020 emissions at the Tracy Plant are now available and show an increase in emissions. To ensure the 4-factor is using the most current emissions baseline, please incorporate these reporting years into the emissions baseline.*

A(a) Based on conversations with NDEP, we understand that this request relates specifically to Unit 6 (Piñon Pine #4), a combined cycle natural gas fired combustion turbine. We understand that NDEP is requesting that a five-year baseline period of 2016 to 2020 be used for evaluation of the cost-effectiveness of possible NOx controls for this turbine, particularly SCR. The original Four Factor analysis used the baseline period of 2016 to 2018. As shown in the table below, the requested 5-year baseline period average NOx emissions for this unit are approximately 17% higher than the original baseline period.

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[6] IPM Model – Updated to Cost and Performance for APC Technologies, SCR Cost Development Methodology, Sargent & Lundy, January 2017, available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.pdf

[7] EPA Retrofit Cost Analyzer Excel Spreadsheet available at: https://www.epa.gov/airmarkets/retrofit-cost-analyzer

NOx performance (lb/MMBtu) is approximately the same, but the unit had slightly higher average firing rate during the 5-year period.

	Period	Gross Load (MW-h)	SO2 (tons)	NOx Rate (Lb/MMBtu)	NOx (tons)	Heat Input (MMBtu)
5 yr avg.	**2016-2020**	**399,053**	**1.0**	0.151	**249.5**	**3,299,941**
Original Baseline	**2016-2018**	**333,734**	**0.8**	0.151	**213.1**	**2,829,205**
				Increase vs Original	**17%**	**17%**

As requested, NVE has used this updated 5-year baseline period emissions, and the other below discussed adjusted operating cost estimates, to generate updated cost-effectiveness calculations for NOx controls to this unit. Attachment C provides these updated cost-effectiveness results for Tracy Unit 6.

NVE believes that either of these baseline periods (the original or the new 5-year baseline) are reasonable representations of the expected near-term future operations of this NG-fired turbine. However, they do not characterize its longer-term operation, as future utilization is influenced by a variety of factors ultimately driven by system demand requirements. Furthermore, as this turbine is already 25 years old, NVE expects to retire this unit within the next 10 years. NVE's current life span assessment has this turbine listed with a 2031 retirement date, which would be approximately 5 years after new controls, if required, would be in service. While this retirement date is an estimate and not a federally enforceable requirement, nevertheless, this turbine is not expected to operate for many additional years.

Because the costs of SCR are dominated by one-time capital expenses, the cost-effectiveness of add-on controls is heavily influenced by assumptions regarding the remaining useful life of the unit. As with previous presentations to NDEP of these costs, NVE is presenting these costs with three different equipment life assumptions: 10-year, 20-year and 30-year remaining life. For the reasons stated above, NVE believes the shorter equipment life cost-effectiveness is the more relevant of these scenarios. The longer remaining life assumptions are unrealistic for this unit but are shown for general informational purposes as had been requested previously.

Tracy Question (b) <u>**Assumed Electricity Cost (SCR Spreadsheet)**</u>

Q(b) *In NVE's electricity cost calculations, an electricity price of 0.0754 $/kWh, however, the SCR Spreadsheet actually assumes an electricity price of 0.0361 $/kWh. Please use the correct electricity price.*

Using this, a new electricity cost of about $74,000 is derived. If NVE feels this price no longer fully includes the cost of derate and SCR pressure drop, please provide the findings of the NVE Resource Planning Department analysis and propose a new cost for derate.

A(b) NDEP's suggested electricity price of 0.0361$/kWh is the 2016 average fossil power plant operating expense from Energy Information Administration (EIA) website (as referenced from an EPA SCR cost spreadsheet). If one uses that value ($0.361/kWh) along with the new requested 5-year baseline period, this results in an estimated annual electricity cost of $86,090/yr. (This is higher than the NDEP referenced $74K due to the higher average capacity utilization during the new requested 5-year baseline period.)

However, this figure doesn't include the costs to NVE associated with the 552 kW lost capacity (derate) of this unit by the SCR backpressure. NVE needs to have sufficient generating capacity available at all times to meet possible customer demands. NVE's system capacity is sufficient for most of the year, but capacity purchases are necessary during the summer months each year. The price to purchase generation capacity averages about $20/kW-month. This is the cost to have capacity available, even if it is not used. (There are additional costs if it is used which we've not included.) The annual cost to replace the 552 kW lost capacity of this turbine for 3 months is $33,130/yr (552 kW * $20/kWh-month * 3 months). Therefore, the total cost of the electricity and derate is the sum of these numbers $86,090 + 33,130 = $119,220.

NVE considers this total cost, including the capacity purchases, to be a reasonable estimate of the electricity cost for adding SCR. This figure is supported by a separate analysis by NVE's Resource Planning Department to identify the total costs associated with a derate to this unit. NVE's analysis using NVE's planning software, indicates that the SCR backpressure derate would result in a total cost due to fuel use and capacity purchases of $120,760/year. This figure is very close to and supports the above cost figure.

NVE has updated the SCR cost estimate using the above cost of $119,220. Further details of these calculations are presented in Attachment D.

Tracy Question (c) Catalyst Changeout Calculation Temperature

Q(c) *Calculations for catalyst changeout assume an SCR inlet temperature as 650°F, however, this should be 750°F for a combined cycle unit.*

A(c) The SCR inlet temperature is relevant to the catalyst changeout costs because it affects the amount of catalyst that is needed. SCR catalyst works most efficiently within a certain temperate range. If the flue gas temperatures are either too high or too low cause, SCR will be less efficient and require more catalyst. Rather than use either 650 F or 750 F temperatures, NVE researched the actual temperature for this particular unit at the location within the Heat Recovery Steam Generator (HRSG) where the SCR would be located. Attachment E is the design specifications for Tracy Unit 6 which shows the temperature at this location in the HRSG is estimated to be 793 F. Attachment F shows the updated catalyst cost calculation using this temperature of 793 F. This calculation has also been updated to reflect the 5-year baseline period, which has a slightly different net plant heat rate, which is one of the other parameters in EPA's formula.

The updated catalyst changeout costs are $137,500/yr and have been used in the updated cost effectiveness analysis.

Tracy Question (d) <u>Silverhawk and Tracy Unit Comparisons</u>

Q(d) *Please make a quick comparison of MW and NOx inlet (lb/hr) for the Silverhawk unit and Tracy #6 to justify using Silverhawk's catalyst changeout data.*

A(d) NVE's original Four Factor Analysis had based the Tracy Unit 6 catalyst changeout costs entirely on the total cost of a recent catalyst changeout at one of NVE's Silverhawk units. The Silverhawk unit is a larger turbine but has a lower SCR inlet NOx concentration. Therefore, the total NOx load on the SCR system is somewhat similar.

However, in NVE's January 15th response to earlier questions from NDEP, NVE revised the basis of the Tracy Unit 6 catalyst changeout calculation. The new calculation is not entirely dependent on the Silverhawk costs (see Attachment D and E of NVE's January 15th response.). Instead, the current catalyst changeout calculation uses an EPA equation to calculate the total amount of catalyst. The Silverhawk catalyst changeout information now is only used as a basis for the unit cost of catalyst changeout (e.g. $365/cubic foot). This cost per cubic feet includes the replacement catalyst, catalyst disposal and labor for the changeout. Since we are only using the unit costs of the Silverhawk catalyst changeout, the total size of the Silverhawk turbine or its SCR system is not relevant. Nevertheless, as requested, the following table summarizes the characteristics of the Silverhawk and Tracy Unit 6.

	Silverhawk	**Tracy Unit 6**
Turbine MW (excluding duct firing)	175 MW	107 MW
Manufacturer/Model	Westinghouse 105D	GE 6FA
Typical NOx PPM @ SCR Inlet	19 ppm	41 ppm
Typical NOx lb/hr @ SCR Inlet	93 lb/hr	91 lbs/hr

(Attachments)

Attachment A
Projection of 2028 Station Output and Emissions

	Station Total	Unit 1	Unit 2
A. Electric Output, 2016–2018 Baseline (MWhr/yr)	1,042,273	466,437	575,835
B. Baseline Output to IPC (MWhr/yr)	350,609	153,216	197,393
C. Baseline Output to SPPC (MWhr/yr) (A – B)	691,664	313,221	378,442
D. 2028 Output = Baseline Output to SPPC (MWhr/yr)	691,664	313,221	378,442
Ratio: 2028 Output/Baseline Output		0.67	0.65
Baseline NOx Emissions (tons/yr)		804	1,002
2028 NOx Emissions*		537	656
Baseline SO2 Emissions (tons/yr)		1,812	501
2028 SO2 Emissions*		1,210	327
Baseline PM Emissions (tons/yr)		22.0	37.7
2028 PM Emissions*		14.7	24.7

*2028 Emissions = Baseline Emissions x Ratio: 2028 Output/Baseline Output

Attachment B
Revised Cost Tables for NV Energy Four Factor Analysis

Table 1 – North Valmy Unit #1 - NOx Control Option Cost-Effectiveness

Selective Non-Catalytic Reduction			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$9,180,000		
Annual Capital Recovery ($/yr)	$1,290,000	$850,000	$720,000
Annual Operating Cost (excl. capital recovery) ($/yr)	$410,000		
Total Annual Costs ($/yr)	$1,700,000	$1,260,000	$1,130,000
Annual Emission Rate with Controls (Tons/yr)	403 tons/yr		
NOx Emission Reduction (Tons/year)	134 tons/yr		
Control Cost Effectiveness ($/Ton)	**$12,679**	**$9,389**	**$8,431**

Selective Catalytic Reduction (SCR)			
	10-year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$112,600,000		
Annual Capital Recovery ($/yr)	$15,840,000	$10,420,000	$8,850,000
Annual Operating Cost (excl. capital recovery) ($/yr)	$1,740,000		
Total Annual Costs ($/yr)	$17,580,000	$12,160,000	$10,590,000
Annual Emission Rate with Controls (Tons/yr)	80 tons/yr		
NOx Emission Reduction (Tons/year)	457 tons/yr		
Control Cost Effectiveness ($/Ton)	**$38,461**	**$26,615**	**$23,167**

Table 2 – North Valmy Unit #2 - NOx Control Option Cost-Effectiveness

Selective Non-Catalytic Reduction			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$9,750,000		
Annual Capital Recovery ($/yr)	$1,370,000	$900,000	$770,000
Annual Operating Cost (excl. capital recovery) ($/yr)	$490,000		
Total Annual Costs ($/yr)	$1,860,000	$1,390,000	$1,260,000
Annual Emission Rate with Controls (Tons/yr)	492 tons/yr		
NOx Emission Reduction (Tons/year)	164 tons/yr		
Control Cost Effectiveness ($/Ton)	**$11,340**	**$8,481**	**$7,649**

Selective Catalytic Reduction			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$130,800,000		
Annual Capital Recovery ($/yr)	$18,405,000	$12,110,000	$12,290,000
Annual Operating Cost (excl. capital recovery) ($/yr)	$2,010,000		
Total Annual Costs ($/yr)	$20,410,000	$14,120,000	$14,280,000
Annual Emission Rate with Controls (Tons/yr)	104 tons/yr		
NOx Emission Reduction (Tons/year)	552 tons/yr		
Control Cost Effectiveness ($/Ton)	**$36,936**	**$25,552**	**$22,238**

Table 3 – North Valmy Unit #1 - Flue Gas Desulfurization Cost-Effectiveness

Equipment Life (years)	Limestone FGD	Lime FGD
20	$22,626 /ton	$21,885 /ton
21	$22,160 /ton	$21,437 /ton
22	$21,757 /ton	$21,050 /ton
23	$21,397 /ton	$20,703 /ton
24	$21,079 /ton	$20,398 /ton
25	$20,782 /ton	$20,112 /ton
26	$20,507 /ton	$19,847 /ton
27	$20,274 /ton	$19,623 /ton
28	$20,040 /ton	$19,399 /ton
29	$19,850 /ton	$19,216 /ton
30	$19,659 /ton	$19,032 /ton

Attachment C

Revised Cost Tables for NV Energy Four Factor Analysis

Tracy Unit #6/Piñon Pine 4 - SCR NOx Control Option Cost-Effectiveness

Updated April 2021

Table C-1   SCR Operating Cost Assumption Changes

Dry Low NOx Combustor Conversion			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$13,464,516		
Annual Capital Recovery ($/yr)	$1,894,950	$1,246,366	$1,057,936
Annual Operating Cost (excl. capital recovery) ($/yr)	$680,000		
Total Annual Costs ($/yr)	$2,574,950	$1,926,366	$1,737,936
Annual Emission Rate with Controls (Tons/yr)	91.3 tons/yr		
NOx Emission Reduction (Tons/year)	158.2		
Control Cost Effectiveness ($/Ton)	**$16,277**	**$12,177**	**$10,986**

Note 1: April - Updated Baseline emissions to 2016-2020 average basis.

Table C-2   SCR Operating Cost Assumption Changes

SCR Operating Costs (Current cost assumptiosn are shown compared to most recent estimate sent to NDEP July 8, 2020.)	July 2021 Response to NDEP	Jan. 2021 Updated Estimate (SCR Only)	April 2021 Updated Estimate	April 2021 Update for SCR w/DLN
Capacity Loss from Derate [(1)]	$167,435	(included)	(included)	(included)
Power Cost due to SCR Pressure Drop (5)	$154,828	$154,828	$119,220	$119,220
Catalyst Changeout Costs (annualized with FWF) [(2, 3)]	$191,000	$140,000	$138,900	$69,450
Annual Maintenance Costs	$38,420	$38,420	$38,420	$38,420
Annual Ammonia Grid Tuning	$40,000	$40,000	$40,000	$40,000
Reagent Usage [(4)]	$129,684	$83,271	$83,271	$29,145
Total Annual Operating Costs (excluding Capital Recovery)	**$721,367**	**$456,519**	**$419,811**	**$296,235**

Notes:

1) January - Assume Derate costs covered in Power costs. No need for extra cost line item.

2) April - Updated SCR Catalyst Inlet Temperature See attachment F (Also, January - Updated Catalyst Changeout costs methodology)

3) With DLN and SCR, assume lower inlet NOx allows 50% less frequent changeouts (same assumption)

4) With DLN and SCR, assume 65% Less reagent with lower NOx ppm at SCR inlet (same assumption)

5) April - recalculated using lower cost of electricity but including capacity purchase.

Attachment C - Revised SCR Cost-Effectiveness (continued)

Table C-3a SCR Cost Effectiveness (Updated April 2021)

(Including 15% EPC adjustment to Capital Cost)

Selective Catalytic Reduction w/existing steam injection			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$8,836,600		
Annual Capital Recovery ($/yr)	$1,243,633	$817,975	$694,311
Annual Operating Cost (excl. capital recovery) ($/yr)	$419,811		
Total Annual Costs ($/yr)	$1,663,444	$1,237,786	$1,114,121
Annual Emission Rate with Controls (Tons/yr)	24.9 tons/yr		
NOx Emission Reduction (Tons/year)	224.5		
Control Cost Effectiveness ($/Ton)	**$7,410**	**$5,514**	**$4,963**

Notes:

1) Capital Cost estimate is the same as in original NVE Four Factor Report and July update except an additional 15% has been added to account for use of EPC contract. EPC adjustment consistent with EPA Retrofit Cost Analyzer (RCA) methodology and Sargent & Lundy Study (backup for RCA). Both EPA and S&L study available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer.

2) Changes to operating costs shown in Table C-2 above.

Attachment C - Revised SCR Cost-Effectiveness (continued)

Table C-3b SCR Cost Effectiveness (Updated April 2021)

(Not including 15% EPC adjustment to Capital Cost)

Selective Catalytic Reduction w/existing steam injection			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$7,684,000		
Annual Capital Recovery ($/yr)	$1,081,420	$711,282	$603,748
Annual Operating Cost (excl. capital recovery) ($/yr)	$419,811		
Total Annual Costs ($/yr)	$1,501,231	$1,131,093	$1,023,559
Annual Emission Rate with Controls (Tons/yr)	24.9 tons/yr		
NOx Emission Reduction (Tons/year)	224.5		
Control Cost Effectiveness ($/Ton)	**$6,687**	**$5,038**	**$4,559**

Notes:

Same as Table C-3a except does not include 15% EPC adjustment.

Attachment C - Revised SCR Cost-Effectiveness (continued)

Table C-4a SCR w/DLN Cost Effectiveness (Updated April 2021)

(Including 15% EPC adjustment to SCR Capital Cost)

Selective Catalytic Reduction and DLN Combustors			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$22,301,116		
Annual Capital Recovery ($/yr)	$3,138,584	$2,064,341	$1,752,247
Annual Operating Cost (excl. capital recovery) ($/yr)	$976,235		
Total Annual Costs ($/yr)	$4,114,818	$3,040,575	$2,728,482
Annual Emission Rate with Controls (Tons/yr)	12.5 tons/yr		
NOx Emission Reduction (Tons/year)	237.0		
Control Cost Effectiveness ($/Ton)	**$17,362**	**$12,829**	**$11,513**
Incremental Cost Effect. vs Just SCR	**$196,110**	**$144,223**	**$129,149**

Capital Cost estimate is the same as sum of costs of SCR and DLN in original NVE Four Factor Report and July update except added 15% EPC adjustment to SCR cost as discussed above. Operating costs for SCR are updated as discussed above. Operating costs for DLN are same as NVE's July 2020 update.

Table C-4b SCR w/DLN Cost Effectiveness (Updated April 2021)

(Not including 15% EPC adjustment to SCR Capital Cost)

Selective Catalytic Reduction and DLN Combustors			
	10 year Life	**20 yr Life**	**30 yr Life**
Estimated Capital Cost ($)	$21,148,516		
Annual Capital Recovery ($/yr)	$2,976,371	$1,957,648	$1,661,684
Annual Operating Cost (excl. capital recovery) ($/yr)	$976,235		
Total Annual Costs ($/yr)	$3,952,605	$2,933,883	$2,637,919
Annual Emission Rate with Controls (Tons/yr)	12.5 tons/yr		
NOx Emission Reduction (Tons/year)	237.0		
Control Cost Effectiveness ($/Ton)	**$16,678**	**$12,379**	**$11,130**
Incremental Cost Effect. vs Just SCR	**$196,110**	**$144,223**	**$129,149**

Costs same as Table C-4a except not including 15% EPC adjustment to SCR capital costs.

Attachment D: Estimate of Tracy Unit 6 Electricity Cost

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)
Bmw	107	Unit Megawatt rating (Nominal Output)
Power 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 fuel only 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/KW-hr
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 summer-time 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 suggested 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 futher lost of capacity availlability must be made up by purchasing generation capacity 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.

Attachment E

WASTE HEAT BOILER
THERMAL PERFORMANCE DATA SHEET

November 30, 1994

·rchaser/Owner	Foster Wheeler / Sierra Pacific	Type	Two (2) Pressure — Natural Circulation
.ation	Reno, Nevada	Number Required	One (1)
Reference	ATS Job No. 1123	Model Number	GE Frame 6FA

This is the location in the HRSG where an SCR would go if installed. Temperature here is 793 F

CASE #6 (Fired)

GAS SIDE		hpsh#2	burner	hpsh#1	hpevap	scr	hpevap	hphtecon	ipsh
GAS FLOW	lb/hr	1,411,960	1,411,960	1,419,175	1,419,175	1,419,175	1,419,175	1,419,175	572,717
INLET PRESSURE	in	15.29	14.06	13.76	12.88	10.95	8.33	5.61	4.47
PRESSURE DROP	in	1.23	0.30	0.88	1.93	2.62	2.71	1.14	0.23
INLET TEMPERATURE	°F	1107.0	1030.6	1353.6	1196.6	793.1	793.1	587.0	407.9
OUTLET TEMPERATURE	°F	1030.6	1353.6	1196.6	793.1	793.1	587.0	407.9	402.5
TEMPERATURE DIFF.	°F	76.4	-323.0	157.0	403.5	.0	206.1	179.1	5.4
SPECIFIC HEAT	BTU/lb/°F	.288		.298	.289		.279	.272	.268
HEAT REJECTED	MMBTU/hr	31.10		66.37	165.38		81.45	69.04	0.63
EFFICIENCY	%	99.0		99.0	99.0		99.0	99.0	99.0
FOULING FACTOR		.001		.001	.001		.001	.001	.001
SUPP. FUEL (lhv)	MMBTU/hr		142.24						
FLOW ARRANGEMENT		Parallel		Counter	Counter		Counter	Counter	Counter

TUBE SIDE		hpsh#2	burner	hpsh#1	hpevap	scr	hpevap	hphtecon	ipsh
FLUID FLOW	lb/hr	329,210		326,991	219,092		107,899	330,261	35,899
ᴵᴺᴸET PRESSURE	psig	974.0		996.5	996.5		996.5	1035.7	55.2
LET PRESSURE	psig	943.0		974.0	996.5		996.5	996.5	48.0
·RESSURE DROP	psig	31.0		22.5	0.0		0.0	39.2	7.2
INLET TEMPERATURE	°F	793.1		546.1	463.5		463.5	267.7	302.9
OUTLET TEMPERATURE	°F	950.0		806.2	546.1		546.1	463.5	342.6
TEMPERATURE RISE	°F	156.9		260.1	82.6		82.6	195.8	39.7
ENTHALPY CHG	BTU/lb	93.5		200.9	747.3		747.3	206.9	22.9
HEAT ABSORBED	MMBTU/hr	30.79		65.71	163.73		80.63	68.35	0.82
FOULING FACTOR		.001		.001	.001		.001	.001	.001
BLOWDOWN	%				1.0		1.0		
ATTEMP FLOW	lb/hr			2,219					
FINAL STEAM TEMP	°F			793					
ADDITIONAL FLOW	lb/hr								

NOTES:

APPLIED THERMAL SYSTEMS, INC.

1123_DS.XLS

WASTE HEAT BOILER
THERMAL PERFORMANCE DATA SHEET

November 30, 1994

-chaser/Owner	Foster Wheeler / Sierra Pacific	Type	Two (2) Pressure — Natural Circulation
.cation	Reno, Nevada	Number Required	One (1)
Reference	ATS Job No. 1123	Model Number	GE Frame 6FA

CASE #6 (Fired)

GAS SIDE		ipevap	ipevap	ipecon	hpltecon	condpreht	stack		
GAS FLOW	lb/hr	846,458	1,419,175	262,162	1,157,013	1,419,175	1,419,175		
INLET PRESSURE	in	4.47	4.24	2.28	2.28	1.86	1.53		
PRESSURE DROP	in	0.23	1.95	0.43	0.43	0.32	0.53		
INLET TEMPERATURE	°F	407.9	395.1	317.0	317.0	287.4	242.7		
OUTLET TEMPERATURE	°F	390.2	317.0	292.0	286.4	242.7	242.7		
TEMPERATURE DIFF.	°F	17.7	78.1	25.0	30.6	44.7	.0		
SPECIFIC HEAT	BTU/lb/°F	.268	.266	.264	.264	.263			
HEAT REJECTED	MMBTU/hr	4.02	29.53	1.73	9.35	16.66			
EFFICIENCY	%	99.0	99.0	99.0	99.0	99.0			
FOULING FACTOR		.001	.001	.001	.001	.001			
SUPP. FUEL (lhv)	MMBTU/hr								
FLOW ARRANGEMENT		Counter	Counter	Counter	Counter	Counter			

TUBE SIDE									
-UID FLOW	lb/hr	4,305	31,593	36,258	330,261	300,000			
ET PRESSURE	psig	55.2	55.2	61.4	1061.3	62.6			
JUTLET PRESSURE	psig	55.2	55.2	55.2	1035.7	60.0			
PRESSURE DROP	psig	0.0	0.0	6.1	25.6	2.6			
INLET TEMPERATURE	°F	286.4	286.4	240.0	240.0	81.2			
OUTLET TEMPERATURE	°F	302.9	302.9	286.4	267.7	136.3			
TEMPERATURE RISE	°F	16.5	16.5	46.4	27.7	55.1			
ENTHALPY CHG	BTU/lb	925.3	925.3	47.3	28.0	55.0			
HEAT ABSORBED	MMBTU/hr	3.98	29.23	1.71	9.25	16.49			
FOULING FACTOR		.001	.001	.001	.001	.001			
BLOWDOWN	%	1.0	1.0						
ATTEMP FLOW	lb/hr								
FINAL STEAM TEMP	°F								
ADDITIONAL FLOW	lb/hr								

NOTES:

Attachment F: 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 using 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 Costs per EPA Cost Control Manual Method 1

Turbine Design Parameters			**Tracy Unit 6 (Pinon Pine #4)**
Bmw	MW Rating at Full Load	107	MW (note this is the gas turbine alone, and excludes duct firing)
NPHR	Net Plant Heat Input Rate	8.27	MMBtu/MW (actual 2016-2020 average)
	Days of Operation	365	days/yr
NOx_{in}	Inlet NOx	0.1512	lb/mmbtu (actual 2016 - 2020 average)
	% control	90.00	% removal for SCR (assumed)
Sulf	Fuel Sulfur Content	0	weight fraction (negligible for Natural Gas)
SCR Assumptions:			
N_{scr}	Number of SCR Reactor Chambers	1	Chambers (EPA default in EPA SCR spreadsheet and CCM)
Rl_{ayer}	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	6.75%	
y	Frequency of Cat. Changeout	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 conservate estimate based on actual catalyst costs for NVE at Silverhawk facility in 2018 which totalled $469/ft3 (see Attach. E of NVE letter to NDEP of January 15, 2021)

Calculated values and adjustment Factors for estimating Catalyst Volume

Q_B	Max. Heat Input Rate	884.89	MMBtu/hr (=Bmw * NPHR)
Ef_{adj}	1.2391	= 0.2869 + (1.058 * %removal/100)	
$Slip_{adj}$	1.1701	= 1.2835 - (0.0567 * Slip)	
NOx_{adj}	0.9009	= 0.8524 + (0.3208 * NOx_{in})	
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	0.31181	= $i*(1/((1+i)^y-1))$

Attachment F: Estimate of SCR Catalyst Annual Costs (continued)

SCR Calculated Catalyst Volume (entire reactor) EPA CCM Methodology 1

Vol_{cat}	Catalyst Volume	3661.90	ft3 (calculated)

Catalyst Volume (ft3) = 2.81 x Q_B x EF_{adj} x $Slip_{adj}$ x NOx_{adj} x S_{adj} x (T_{adj}/N_{vfu})

Calc. Annual Catalyst Costs (assuming only one layer (1/3 of total) catalyst is replaced each Changeout.

Annual Catalyst Cost	**$138,920**	**$/yr** = N_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF
w/365 $/ft3		(FYI - one time cost to change entire catalyst)
		$1,336,592 = Nscr x Volcat x CCreplace

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	***$178,505***	***$/yr*** *= N_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF*
w/469 $/ft3		

Attachment G

Sargent & Lundy DSI Evaluation for North Valmy Unit 1

and

Sargent & Lundy SCR and WFGD Retrofit Report for North Valmy

REDACTED

March 1, 2021

Dariusz Rekowski
Vice President, Power Generation
Sierra Pacific Power Company d/b/a NV Energy
P.O. Box 98910, M/S 25
Las Vegas, NV 89151

Re: Approval of Request for Confidentiality for Emission Control Analyses related to the Regional Haze Program, FIN A0375, – Sierra Pacific Power Company d/b/a NV Energy – North Valmy Generating Station

Dear Mr. Rekowski:

The Nevada Division of Environmental Protection – Bureau of Air Quality Planning (BAQP) has reviewed the confidentiality request for the above-referenced Air Case from Sierra Pacific Power Company d/b/a NV Energy, received on February 23, 2021. Based on review and recommendation, I hereby approve the request for confidentiality of those items in the aforementioned request pursuant to Nevada Revised Statutes (NRS) 445B.570.

This approval only applies to this specific request with the BAQP Planning Branch, and a new request must be submitted for any future permit actions containing confidential information. This approval does not apply to the BAPC's Chemical Accident Prevention Program (CAPP), the Compliance Branch, or any other bureau of the Nevada Division of Environmental Protection. Pursuant to NRS 445B.570, the BAQP will verify the content of the confidential information once the application and/or information submittal is received to ensure the information declared confidential conforms with the request. Sierra Pacific Power Company d/b/a NV Energy must submit both public and confidential copies of the application and/or information submittal. Please do not submit confidential information by email. If you have any questions, please feel free to contact Sigurd Jaunarajs, Supervisor, at (775) 687- 9392 or sjaunara@ndep.nv.gov.

Sincerely,

Greg Lovato, P.E.
Administrator
Nevada Division of Environmental Protection

GL/JK/DD/SJ/SM
Enclosure: Bureau of Air Quality Planning (BAQP) – Planning Branch Confidentiality Request Form
E-Copy: Dariusz Rekowski, Sierra Pacific Power Company d/b/a NV Energy

Appendix B.5.f - Response Letter 4

NVEnergy

May 7, 2021

Steven McNeece
Nevada Department of Environmental Protection
901 S. Stewart Street
Suite 4001
Reno, NV 89701

Re: Response to a Fourth Follow-up Request for Additional Information
Regional Haze Four Factor Analyses
NV Energy Tracy (FIN 0029) and Valmy (FIN A0375) Generating Stations

Mr. McNeece:

Per your email correspondence dated April 21, 2021, Nevada Power Company d/b/a NV Energy (NVE) hereby provides a response detailing Nevada Division of Environmental Protection (NDEP)'s most recent request for additional information regarding the Four Factor Analyses at both the Tracy and North Valmy Generating Stations previously submitted April 16, 2021. Please note that this is the response to NDEP's fourth follow-up request for additional information, as NVE also provided responses to NDEP's first request for additional information in a letter dated July 8, 2020, as well as a second request for additional information in a letter dated January 15, 2021, and a third request for additional information in a letter dated April 16, 2021. This letter and attachments address NDEP's most recent questions and should be considered a fourth addendum to the previously submitted Four Factor Analyses.

NVE appreciates the opportunity to work with NDEP in this endeavor. Please feel free to contact Sean Spitzer at (702) 402-5132 should you have any questions.

Sincerely,

Starla Lacy

Starla Lacy
Vice President, Environmental Services, Safety, and Land Management
NV Energy

Tracy Unit 6 SCR EPC Contract Cost Follow-up Response:

NDEP requested additional information about the EPC cost factor included in the updated capital cost estimate for SCR for Tracy Unit #6. Specifically, NDEP requested whether NVE would plan to have the project executed on a "turnkey" basis. Also, NDEP inquired what specific cost items are included in what NVE has called "EPC". The following answers these two questions:

"Turnkey"? Yes, NVE expects if SCR were required for Unit #6 at Tracy, that the project to install SCR would be executed as a turnkey EPC contract with a contractor that would take overall responsibility for the project (in contrast to using multiple lump-sum contracts or other cost structure). Under a turnkey EPC-type contract, a single EPC contractor would have overall responsibility for the engineering design of the system, procurement of the equipment, field construction and commissioning of the project as well as guaranteeing its performance, meeting the project schedule, and other contract commitments. Upon completion of the project, the turnkey contractor would turn over the completed project to NVE. However, notwithstanding these responsibilities of the contractor, NVE could not be completely hands-off on a project to retrofit SCR to an existing generating unit. NVE still has ultimate environmental compliance responsibility and would be significantly involved in the SCR project to be comfortable that it would not negatively impact the unit's performance or compliance. Likewise, NVE would need to coordinate the EPC contractor's activities with the unit operations.

Specific Costs Included? Because the EPC contractor will have overall responsibility for the project execution and performance, they would be expected to incur several costs that are not included in the SCR vendor budgetary price quote upon which NVE's Unit 6 SCR capital costs are based. The extra costs we've attempted to address with an extra 15% EPC factor include the following additional costs that the EPC contractor would be expected to incur. These additional costs would be passed on to NVE in project fees paid to the contractor:

- Extra procurement costs associated with managing and negotiating subcontracts;
- Extra construction supervision and project management to provide overall oversight to all subcontractors and other work on the job to assure compliance with schedule commitments and quality commitments;
- Extra engineering by the EPC contractor to verify and develop confidence that the design will meet performance requirements of the system and extra oversight during commissioning, startup, and performance testing to assure system compliance with guarantees; and
- Extra EPC contractor fees/markup to account for the increased risk and or insurance costs taken on by EPC contractor regarding schedule and performance guarantees.

The above extra EPC contractor costs are not included in the SCR vendor budgetary quote or other costs separately included in NVE's capital cost estimate. These indirect installation costs are consistent with costs allowed by EPA's Cost Control Manual. The use of a 15% factor to account for these extra EPC costs is consistent with the value used in EPA's own "Retrofit Cost Analyzer"

(RCA) Excel-based tool for estimating SCR costs and the EPA sponsored Sargent & Lundy 2017 study which updated that EPA cost tool.[1]

Valmy Station Cost and Emissions Comparison – Change in Projected Future Output

In the original Four Factor Analysis for the North Valmy Generating Station submitted to the Nevada Department of Environmental Protection (NDEP) in March 2020, the uncontrolled emission rates and the costs of technically-feasible alternative emission controls for nitrogen oxides (NOx) and sulfur dioxide (SO2) were estimated based on a projected future station output at the end of calendar year 2028 (i.e., end of the second decadal regional haze review and implementation period) based on the station's output during the 2016-2018 baseline years minus the output during that period that was generated to support power drawn by Idaho Power Company (IPC). This same methodology was used to prepare the estimated costs associated with replacing the existing dry sorbent injection (DSI) system on North Valmy Unit 1 with a DSI system designed to control SO2 emissions when responding to comments on the Four Factor analysis posed by NDEP in a follow up request for additional information.

The attached table summarizes how these originally-provided cost and emissions estimates compare to the use of station output and emissions projections that assume that North Valmy would operate at the unadjusted 2016-2018 baseline operating level in the future. As shown in the attachment, the unadjusted 2016-2018 baseline output level is approximately 34% higher than the output level that was presented in the Four Factor Analysis. Consequently, the annualized cost of each alternative and the annual quantity of emissions reduction that would be achieved are correspondingly higher than estimated in the Four Factor Analysis.

In addition, the estimated costs associated with the use of the 2016-2018 baseline levels as the future case output of the North Valmy Station take into account responses to questions raised by NDEP in all subsequent comments following submittal of the Four Factor Analysis. In particular, the estimated annualized capital cost of each alternative utilizes the rate of return on investment (ROI) that NVE is allowed by the Public Utility Commission of Nevada (6.75%) rather than the nominal ROI rate of 7% that was utilized in the Four Factor Analysis. In addition, per NDEP's direction, the estimated cost and emissions reduction quantity associated with Selective Catalytic Reduction (SCR) for the control of NOx emissions assumes that this alternative is capable of an outlet emissions concentration of 0.05 lb/MMBtu (as compared to a level of 0.07 lb/MMBtu used in the Four Factor Analysis).

Although the annualized operating costs of each alternative are generally higher when based on the unadjusted 2016-2018 baseline output, the estimated control cost effectiveness (i.e., annualized cost of control divided by annual emissions reduction) are lower than previously estimated because the increase in uncontrolled emission levels is proportionally higher than the increase in estimated annualized costs.

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[1] EPA Retrofit Cost Analyzer Excel Spreadsheet and background documentation are both available at: https://www.epa.gov/airmarkets/retrofit-cost-analyzer

North Valmy Generating Station
Cost and Emissions Comparison - Change in Projected Future Output

Projection:	per 4 Factor Report	2016-2018 Baseline
Input Data		
Projected Future Annual Output (MWhrs)		
Unit 1	313,221	466,437
Unit 2	378,442	575,835
Interest rate used for capital recovery	7.00%	6.75%
SCR output level (lb/MMBtu)	0.07	0.05

North Valmy Unit 1		
SELECTIVE NON-CATALYTIC REDUCTION FOR NOx CONTROL		
Estimated Capital Cost	$9.18 million	$9.18 million
Estimated Annualized Capital Cost	$0.85 million/yr	$0.85 million/yr
Estimated Annual O&M Cost	$0.43 million/yr	$0.54 million/yr
Estimated Total Annual Cost	$1.28 million/yr	$1.39 million/yr
Uncontrolled NOx Emissions	537 tons/yr	804 tons/yr
NOx Emission Reduction with SNCR	134 tons/yr	200 tons/yr
Control Cost Effectiveness	$9,512/ton	$6,961/ton
SELECTIVE CATALYTIC REDUCTION FOR NOx CONTROL		
Estimated Capital Cost	$111.1 million	$126.7 million
Estimated Annualized Capital Cost	$10.48 million/yr	$11.73 million/yr
Estimated Annual O&M Cost	$1.67 million/yr	$1.99 million/yr
Estimated Total Annual Cost	$12.15 million/yr	$13.72 million/yr
Uncontrolled NOx Emissions	537 tons/yr	804 tons/yr
NOx Emission Reduction with SCR	425 tons/yr	681 tons/yr
Control Cost Effectiveness	$28,583/ton	$20,168/ton
LIMESTONE BASED FLUE GAS DESULFURIZATION FOR SO2 CONTROL		
Estimated Capital Cost	$247.8 million	$247.8 million
Estimated Annualized Capital Cost	$23.40 million/yr	$22.95 million/yr
Estimated Annual O&M Cost	$3.50 million/yr	$3.75 million/yr
Estimated Total Annual Cost	$26.90 million/yr	$26.70 million/yr
Uncontrolled SO2 Emissions	1,210 tons/yr	1,812 tons/yr
SO2 Emission Reduction with Limestone FGD	1,169 tons/yr	1,751 tons/yr
Control Cost Effectiveness	$23,008/ton	$15,250/ton
LIME BASED FLUE GAS DESULFURIZATION FOR SO2 CONTROL		
Estimated Capital Cost	$238.2 million	$238.2 million
Estimated Annualized Capital Cost	$22.49 million/yr	$22.06 million/yr
Estimated Annual O&M Cost	$3.53 million/yr	$3.82 million/yr
Estimated Total Annual Cost	$26.02 million/yr	$25.88 million/yr
Uncontrolled SO2 Emissions	1,210 tons/yr	1,812 tons/yr
SO2 Emission Reduction with Lime FGD	1,169 tons/yr	1,751 tons/yr
Control Cost Effectiveness	$22,252/ton	$14,782/ton
DRY SORBENT INJECTION FOR SO2 CONTROL		
Estimated Capital Cost	$37.4 million	$37.4 million
Estimated Annualized Capital Cost	$2.94 million/yr	$3.47 million/yr
Estimated Annual O&M Cost	$3.76 million/yr	$4.27 million/yr
Estimated Total Annual Cost	$6.70 million/yr	$7.74 million/yr
Uncontrolled SO2 Emissions	1,210 tons/yr	1,812 tons/yr
SO2 Emission Reduction with Lime DSI	892 tons/yr	1,338 tons/yr
Control Cost Effectiveness	$7,516/ton	$5,786/ton

North Valmy Unit 2		
SELECTIVE NON-CATALYTIC REDUCTION FOR NOx CONTROL		
Estimated Capital Cost	$9.75 million	$9.75 million
Estimated Annualized Capital Cost	$0.92 million/yr	$0.90 million/yr
Estimated Annual O&M Cost	$0.49 million/yr	$0.67 million/yr
Estimated Total Annual Cost	$1.41 million/yr	$1.57 million/yr
Uncontrolled NOx Emissions	657 tons/yr	1,002 tons/yr
NOx Emission Reduction with SNCR	164 tons/yr	250 tons/yr
Control Cost Effectiveness	$8,588/ton	$6,280/ton
SELECTIVE CATALYTIC REDUCTION FOR NOx CONTROL		
Estimated Capital Cost	$128.9 million	$147.2 million
Estimated Annualized Capital Cost	$12.17 million/yr	$13.63 million/yr
Estimated Annual O&M Cost	$1.92 million/yr	$2.34 million/yr
Estimated Total Annual Cost	$14.09 million/yr	$15.97 million/yr
Uncontrolled NOx Emissions	657 tons/yr	1,002 tons/yr
NOx Emission Reduction with SCR	511 tons/yr	841 tons/yr
Control Cost Effectiveness	$27,559/ton	$18,989/ton

Appendix B.5.g - Response Letter 5.1

August 27, 2021

Steven McNeece
Nevada Department of Environmental Protection
901 S. Stewart Street
Suite 4001
Reno, NV 89701

Re: Response to a Fifth Follow-up Request for Additional Information
Regional Haze Four Factor Analyses
NV Energy Tracy (FIN 0029) and Valmy (FIN A0375) Generating Stations

Mr. McNeece:

Per your email correspondence dated July 14, 2021, Sierra Pacific Power Company d/b/a NV Energy (NVE) hereby provides a response detailing Nevada Division of Environmental Protection (NDEP)'s most recent request for additional information regarding the Four Factor Analyses at both the Tracy and North Valmy Generating Stations. Per our subsequent phone conversation in August 2021, this response only addresses the questions related to the Valmy Generating Station. NVE will provide a response to the questions addressing the Tracy Generating Station in a future letter.

Please note that this is the response to NDEP's fifth follow-up request for additional information, as NVE also provided responses to NDEP's first request for additional information in a letter dated July 8, 2020, as well as a second request for additional information in a letter dated January 15, 2021, a third request for additional information in a letter dated April 16, 2021, and a fourth request for additional information in a letter dated May 7, 2021. This letter and attachment address NDEP's most recent questions and should be considered a fifth addendum to the previously submitted Four Factor Analyses.

NVE appreciates the opportunity to work with NDEP in this endeavor. Please feel free to contact Sean Spitzer at (702) 402-5132 should you have any questions.

Sincerely,

Starla Lacy

Starla Lacy
Vice President, Environmental Services, Safety, and Land Management
NV Energy

Valmy Follow-up Response:

Q1) Baseline Capacity used for North Valmy in 4-Factor

Please submit NV Energy's decision on which baseline capacity, either "Reduced" or "Full" capacity, will be selected for the final four-factor analysis and subsequent control determination.

A1) In the transmittal dated July 14, 2021, NDEP has indicated its preliminary determination that Selective Non-Catalytic Reduction (SNCR) on Units 1 and 2 and the use of Dry Sorbent Injection (DSI) for control of SO2 emissions on Unit 1 were cost effective and necessary controls needed to ensure reasonable progress towards visibility improvements at the Jarbidge Class I area. However, the annualized cost estimates for these control alternatives, and the cost effectiveness figures which are based on those estimates, assume that both units at Valmy will have a service life of at least 20 years after the controls are implemented. Per our July 22, 2021 discussion, NVE is committed to cease coal burning operations at Valmy Units 1 and 2 no later than December 31, 2028 and proposes to incorporate this date as a federally enforceable permit condition. Given this commitment and considering the time that is needed to implement new emission controls at the Station, from a practical perspective the actual service life of SNCR and DSI would therefore be a limited number of years and substantially less than 20 years, rendering these controls much less cost effective than characterized previously. Accordingly, NVE is providing updated cost effectiveness tables (see Appendix A).

The charts in Appendix A show cost effectiveness figures for each emission control option as a function of control system service life from years 1 through 10 as requested verbally by NDEP during our July call. These charts were developed using the capital cost information about each alternative as provided in previous responses. The emission reduction estimates assume that the annual electrical output of Units 1 and 2 following control system implementation will be the same as the units' actual output during the 2016-2018 baseline, i.e. the "full capacity" baseline period, as summarized in our response to your comments provided on May 7, 2021.

In summary, these charts demonstrate that it would not be cost effective to retrofit Units 1 and 2 with SNCR systems for control of NOx or to install a DSI system for SO2 control on Unit 1. As the 2028 enforceable shutdown date shortens the life expectancy of the controls, the data in the revised tables clearly demonstrates that each of the controls is cost-prohibitive when evaluated at approximately 4 years of life of controls assuming implementation in year 2025; SNCR systems would have cost effectiveness figures of approximately $16,200 per ton controlled for Unit 1 and $14,100 per ton controlled for Unit 2, while a replacement DSI system on Unit 1 would have a cost effectiveness figure of $11,400 per ton controlled.

Q2) Compliance Schedules

Information submitted under the second statutory factor for all evaluated controls, time necessary for compliance, is insufficient. A more detailed and distinguished compliance schedule, that is as expeditious as possible, is needed to determine a more specific compliance deadline for each control. Planned outages and time needed for EPA to approve the SIP should be included.

This information is only needed for the controls outlined in this request, or, SCR on Unit 6 at Tracy Generating Station, and SNCR on both units at Valmy Generating Station should NV Energy select *the "Full Capacity" scenario. The compliance schedule included in the Dry Sorbent Injection analysis should have enough information to determine a compliance date. NV Energy can revise the submitted timeline to incorporate planned outages into the schedule and consider the time needed for EPA to approve the SIP, if desired.*

A2) Valmy

Note that as per the response provided in the previous question, none of the controls at Valmy are cost-effective when evaluated on the shortened life expectancy ending in 2028. Therefore, detailed schedule estimates for implementing such controls are also not necessary. Furthermore, without engaging engineering resources to carry out current site-specific design studies for implementation of SNCR or DSI at North Valmy, determining definitive compliance dates that these systems could be put into service is speculative. However, to satisfy the prompt, NVE is providing preliminary estimates of time necessary for compliance as requested.

In the previously submitted 4 factor analysis, NVE provided an estimate for implementing SNCR on either unit at Valmy of at least 6 years following SIP approval. This estimate was partially informed by historic experience with the challenges of equipment retrofit issues, as well as the 2009 Sargent & Lundy SCR and WFGD Retrofit Report's preliminary project schedule estimates. While the S&L report did not explicitly evaluate the project schedule associated with Selective Non-Catalytic Reduction, many of the major project milestones are similar to their SCR project schedule estimate. However, the lack of need for a catalyst could potentially allow for a shorter project schedule. Accordingly, a revised project schedule which includes lead times associated with design, procurement, delivery, installation, and startup of the system, plus contingency for unknowns as well as potential delay of construction to coincide with a pre-planned outage, is provided below:

Valmy - SNCR installation schedule estimate		
	Months	
Process Flow	***(low)***	***(high)***
Develop Scope of Work	1	2
Evaluation, Negotiation, and Contract Award to EPC	1	2
Engineering & Design	3	6
Procurement	3	4
Delivery	3	6
Delay to coincide with outage	1	4
Installation	2	3
Commissioning/Startup	1	2
Schedule Contingency/EPA SIP approval	3	6
Total	**18**	**35**

The estimate of length of time needed to implement SNCR on either unit is 18 months for the most optimistic schedule and 35 months for the most conservative schedule. For planning purposes, NVE asserts that 35 months is an appropriate deadline for SNCR installation on either unit to ensure all aspects of the project can be implemented successfully.

Additionally, NDEP noted in the prompt that the previously provided Sargent & Lundy 2012 Evaluation of Dry Sorbent Injection Demonstration for SO2 Control includes sufficient detail to determine a compliance date, but that NVE may revise the estimate to incorporate time needed for SIP approval and planned outages. In this regard, NVE estimates 1 to 4 months of planned outage delay, and 3 to 6 months of schedule contingency to account for unknowns as well as time necessary for EPA to approve the SIP. Considering the S&L estimate of 24 months for DSI implementation and factoring in the conservative range estimates associated with outage and contingency, NVE asserts that—for planning purposes—34 months is an appropriate deadline for DSI installation to ensure all aspects of the project can be implemented successfully.

Lastly, it should be noted that based on NDEP's draft determination requiring SNCR on both units and DSI on Unit 1, it is implied that all three emission control projects would be implemented concurrently. Therefore, based on the added complexity of managing and coordinating three project schedules simultaneously, NVE asserts that the most conservative estimate of 35 months be used in determining the deadline for a compliance date for all of the controls. In this regard, SNCR and DSI systems would have service lives of at most only 4 years before the final retirement date of the Station.

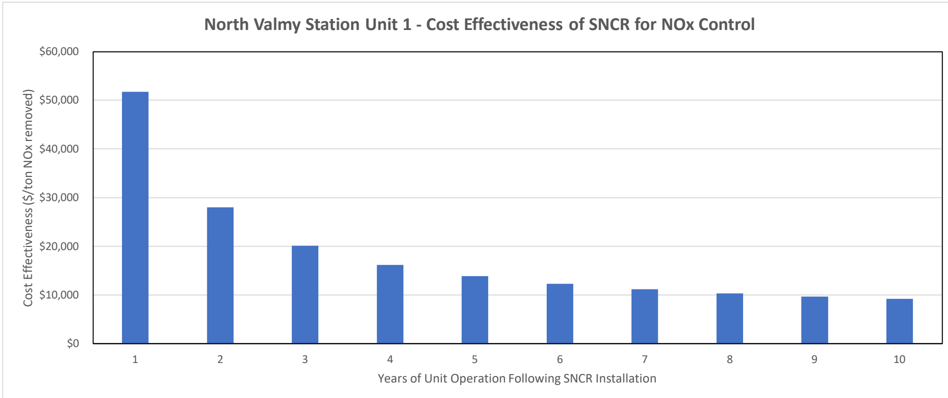
APPENDIX A

Revised Cost Effectiveness Tables for Valmy

North Valmy NOx and SO2 Emission Controls
Impact of Station Retirement Date on Emission Control System Cost Effectiveness

1. Unit 1: Selective Non-Catalytic Reduction (SNCR) for NOx Control

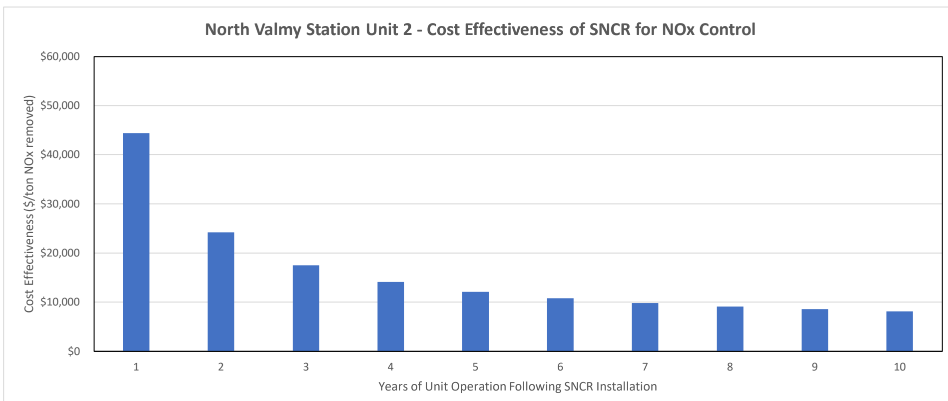
Estimated Total Capital Cost:	$9,179,239									
Estimated Annual NOx Emission Reduction (tons/yr):	200									
Estimated Direct Annual Cost:	$536,697									
Years of Unit Operation following SNCR Installation	1	2	3	4	5	6	7	8	9	10
Estimated Indirect Annual Cost:	$9,802,968	$5,063,727	$3,485,816	$2,699,155	$2,228,260	$1,915,248	$1,692,193	$1,526,048	$1,398,457	$1,295,650
Estimated Total Annual Cost:	$10,339,665	$5,600,424	$4,022,513	$3,235,852	$2,764,957	$2,451,945	$2,228,890	$2,062,745	$1,935,154	$1,832,347
Control Cost Effectiveness ($/ton controlled)	$51,747	$28,029	$20,132	$16,195	$13,838	$12,271	$11,155	$10,324	$9,685	$9,170



Anticipated system installation timeframe:	35 months
Prospective project initiation date:	January 2022
Possible project completion date:	December 2024
Unit retirement date:	December 2028
Possible SNCR system operating life:	4 years
SNCR cost effectiveness estimate:	~$16,200 per ton

2. Unit 2: Selective Non-Catalytic Reduction (SNCR) for NOx Control

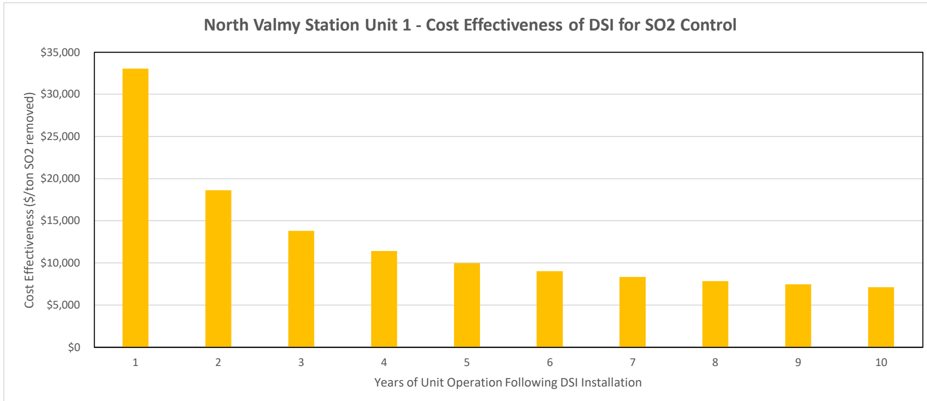
Estimated Total Capital Cost:	$9,751,966									
Estimated Annual NOx Emission Reduction (tons/yr):	250									
Estimated Direct Annual Cost:	$660,378									
Years of Unit Operation following SNCR Installation	1	2	3	4	5	6	7	8	9	10
Estimated Indirect Annual Cost:	$10,414,612	$5,379,672	$3,703,309	$2,867,566	$2,367,290	$2,034,748	$1,797,775	$1,621,264	$1,485,712	$1,376,490
Estimated Total Annual Cost:	$11,074,990	$6,040,050	$4,363,687	$3,527,944	$3,027,668	$2,695,126	$2,458,153	$2,281,642	$2,146,090	$2,036,868
Control Cost Effectiveness ($/ton controlled)	$44,361	$24,193	$17,479	$14,131	$12,127	$10,795	$9,846	$9,139	$8,596	$8,159



Anticipated system installation timeframe:	35 months
Prospective project initiation date:	January 2022
Possible project completion date:	December 2024
Unit retirement date:	December 2028
Possible SNCR system operating life:	4 years
SNCR cost effectiveness estimate:	~$14,100 per ton

3. Unit 1: Trona-based Dry Sorbent Injection (DSI) for SO2 Control

Estimated Total Capital Cost:	$37,420,500									
Estimated Annual SO2 Emission Reduction (tons/yr):	1,338									
Estimated Direct Annual Cost:	$794,200									
Years of Unit Operation following DSI Installation	1	2	3	4	5	6	7	8	9	10
Estimated Indirect Annual Cost:	$43,427,200	$24,107,000	$17,674,400	$14,467,500	$12,547,800	$11,271,700	$10,362,400	$9,685,100	$9,165,000	$8,745,900
Estimated Total Annual Cost:	$44,221,400	$24,901,200	$18,468,600	$15,261,700	$13,342,000	$12,065,900	$11,156,600	$10,479,300	$9,959,200	$9,540,100
Control Cost Effectiveness ($/ton controlled)	$33,059	$18,616	$13,807	$11,409	$9,974	$9,020	$8,340	$7,834	$7,445	$7,132



Anticipated system installation timeframe:	34 months
Prospective project initiation date:	January 2022
Possible project completion date:	November 2024
Unit retirement date:	December 2028
Possible DSI system operating life:	4 years
DSI cost effectiveness estimate:	~$11,400 per ton

Appendix B.5.h - Response Letter 5.2

NVEnergy

October 11, 2021

Steven McNeece
Nevada Department of Environmental Protection
901 S. Stewart Street
Suite 4001
Reno, NV 89701

Re: Response to a Fifth Follow-up Request for Additional Information
Regional Haze Four Factor Analyses
NV Energy Tracy (FIN 0029) and Valmy (FIN A0375) Generating Stations

Mr. McNeece:

Per your email correspondence dated July 14, 2021, Sierra Pacific Power Company d/b/a NV Energy (NVE) hereby provides a response detailing Nevada Division of Environmental Protection (NDEP)'s most recent request for additional information regarding the Four Factor Analyses at both the Tracy and North Valmy Generating Stations. Per our subsequent phone conversation on August 17, 2021, this response only addresses the questions related to the Tracy Generating Station. NVE previously provided a response to the questions addressing the Valmy Generating Station in a letter dated August 27, 2021.

Please note that this is the response to NDEP's fifth follow-up request for additional information, as NVE also provided responses to NDEP's first request for additional information in a letter dated July 8, 2020, as well as a second request for additional information in a letter dated January 15, 2021, a third request for additional information in a letter dated April 16, 2021, and a fourth request for additional information in a letter dated May 7, 2021. This letter and attachment address NDEP's most recent questions and should be considered a fifth addendum to the previously submitted Four Factor Analyses.

NVE appreciates the opportunity to work with NDEP in this endeavor. Please feel free to contact Sean Spitzer at (702) 402-5132 should you have any questions.

Sincerely,

Starla Lacy

Starla Lacy
Vice President, Environmental Services, Safety, and Land Management
NV Energy

Tracy Follow-up Response:

Q2) Compliance Schedules

Information submitted under the second statutory factor for all evaluated controls, time necessary for compliance, is insufficient. A more detailed and distinguished compliance schedule, that is as expeditious as possible, is needed to determine a more specific compliance deadline for each control. Planned outages and time needed for EPA to approve the SIP should be included.

This information is only needed for the controls outlined in this request, or, SCR on Unit 6 at Tracy Generating Station, and SNCR on both units at Valmy Generating Station should NV Energy select the "Full Capacity" scenario. The compliance schedule included in the Dry Sorbent Injection analysis should have enough information to determine a compliance date. NV Energy can revise the submitted timeline to incorporate planned outages into the schedule and consider the time needed for EPA to approve the SIP, if desired.

A2) Tracy

In the transmittal dated July 14, 2021, NDEP has indicated its preliminary determination that Selective Catalytic Reduction (SCR) on Tracy Unit 6 (Pinion Pine) for control of NOx emissions were cost effective and necessary controls needed to ensure reasonable progress towards visibility improvements at the Desolation Wilderness Class I area. However, the annualized cost estimates for this control, and the cost effectiveness figures which are based on that estimate, assume that this unit will have a service life of 30 years after the controls are implemented.

After consideration, NVE is committed to cease operations at Tracy Pinion Pine no later than December 31, 2031, and proposes to incorporate this date as a federally enforceable permit condition, per our August 17, 2021 discussion. Given this commitment and considering the time that is needed to implement new emission controls at the Station, from a practical perspective the actual service life of SCR would therefore be a limited number of years and substantially less than 30 years, rendering these controls much less cost effective than characterized previously. Accordingly, NVE is providing updated cost effectiveness tables (see Appendix A).

The charts in Appendix A show cost effectiveness figures for SCR as a function of control system service life for select years 1 through 30. These charts were developed using the capital cost information about the control option including adjustment for EPC contractor utilization, as provided in previous responses. The emission reduction estimates assume that the annual electrical output of Tracy Pinion Pine following control system implementation will be the same as the unit's actual output during the 2016-2020 baseline, as summarized in our previous responses.

In summary, these charts demonstrate that it would not be cost effective to retrofit Tracy Pinion Pine with an SCR system for control of NOx if the life expectancy of the system is relatively short. The 2031 enforceable shutdown date shortens the life expectancy of the control to approximately 6 years based on NVE's below estimate of the time that would be required to implement SCR (assuming implementation in year 2026). With this short of a life, an SCR system would have a cost effectiveness of approximately $10,000 per ton controlled which is clearly cost-prohibitive.

In sum, implementing SCR control at Tracy Pinion is not cost-effective when evaluated on the shortened life expectancy ending in 2031. Therefore, providing a detailed schedule estimate for implementing such a control is also not necessary. Furthermore, without engaging engineering resources to carry out a current site-specific design study for implementation of SCR, determining a definitive compliance date that this system could be put into service is speculative. However, to satisfy the prompt, NVE is providing a preliminary estimate of time necessary for compliance as requested.

In the previously submitted 4 factor analysis, NVE provided an estimate for implementing SCR on Tracy Pinion Pine of 2-4 years following SIP approval. This estimate was partially informed by recent historic experience with an SCR installation at another NVE facility (Silverhawk Generating Station). In order to provide additional detail, a project schedule which includes lead times associated with design, procurement, delivery, installation, and startup of the system, plus contingency for unknowns as well as potential delay of construction to coincide with a pre-planned outage, is provided below:

Tracy - SCR installation schedule estimate		
	Months	
Process Flow	***(low)***	***(high)***
Develop Scope of Work	1	2
Evaluation, Negotiation, and Contract Award to EPC	1	2
Engineering & Design	6	9
Procurement	3	4
Delivery	6	9
Delay to coincide with outage	1	9
Installation	3	4
Commissioning/Startup	1	2
Schedule Contingency/EPA SIP approval	3	6
Total	**25**	**47**

The estimate of length of time needed to implement SCR on Tracy Pinion is 25 months for the most optimistic schedule and 47 months for a more conservative schedule. For planning purposes, NVE asserts that 47 months is an appropriate deadline for SCR installation on Tracy Pinion to ensure all aspects of the project can be implemented successfully. In this regard, SCR would have a service life of at most only 6 years before permanent shutdown of the unit.

Q3) Optional Emission Limit, Averaging Period, and other requirements Proposal

Controls that are deemed necessary to achieve reasonable progress are required to have a respective new emission limit, averaging period, compliance schedule, and other measures like monitoring, record keeping, and reporting requirements. NV Energy is welcome, but not required, to propose corresponding control requirements for each selected control, depending on the baseline capacity NV Energy selects. Page 42 of EPA's Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (8-20-2019) provides further *explanation and direction on establishing these requirements in a manner that properly reflects the use of controls to ensure reasonable progress is achieved.*

A3) Tracy and Valmy

Based on the previous responses detailing NVE's commitment to shut down Pinion Pine at Tracy by December 31, 2031, as well as both Units 1 & 2 at Valmy by December 31, 2028, each via federally enforceable permit conditions, it is not necessary to propose additional details regarding the selected controls in NDEP's initial determination.

APPENDIX A

Revised Cost Effectiveness Table for Tracy

Appendix A

Revised Cost Tables for NV Energy Four Factor Analysis

Tracy Unit #6/Piñon Pine 4 - SCR NOx Control Option Cost-Effectiveness

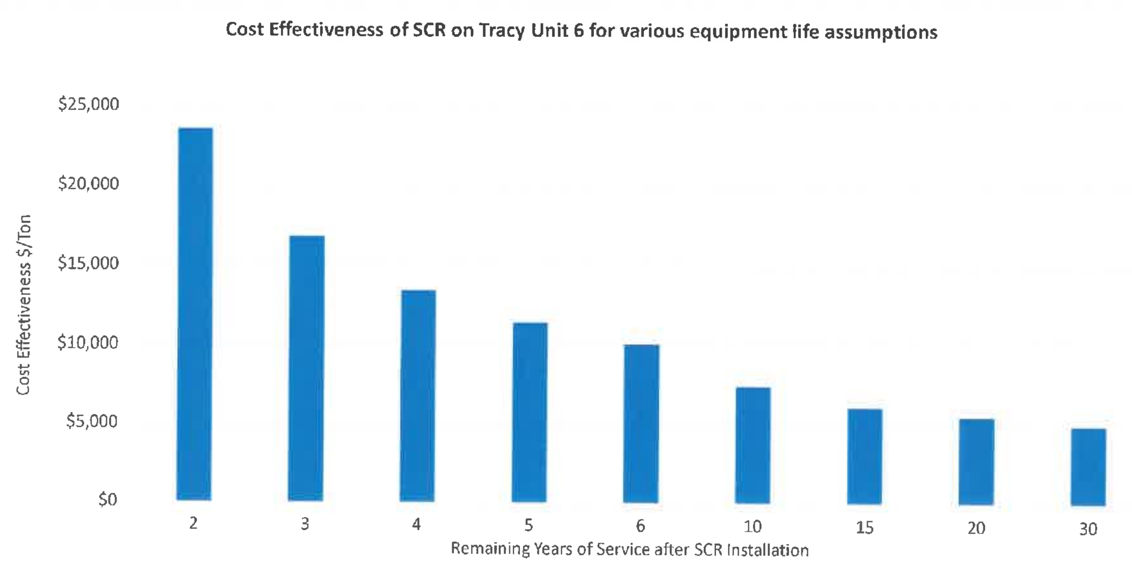
SCR Cost Effectiveness (Updated April 2021)

(Including 15% EPC adjustment to Capital Cost)

Selective Catalytic Reduction w/existing steam injection									
Year life assumption	2	3	4	5	6	10	15	20	30
Estimated Capital Cost ($)	$8,836,600								
Annual Capital Recovery ($/yr)	$4,870,521	$3,351,832	$2,594,105	$2,140,758	$1,839,598	$1,243,633	$954,947	$817,975	$694,311
Annual Operating Cost (excl. capital recovery) ($/yr)	$419,811								
Total Annual Costs ($/yr)	$5,290,332	$3,771,643	$3,013,916	$2,560,569	$2,259,408	$1,663,444	$1,374,758	$1,237,786	$1,114,121
Annual Emission Rate with Controls (Tons/yr)	24.9 tons/yr								
NOx Emission Reduction (Tons/year)	224.5								
Control Cost Effectiveness ($/Ton)	**$23,565**	**$16,800**	**$13,425**	**$11,406**	**$10,064**	**$7,410**	**$6,124**	**$5,514**	**$4,963**

Notes:

1) Capital Cost estimate is the same as in original NVE Four Factor Report and July update except an additional 15% has been added to account for use of EPC contract. EPC adjustment consistent with EPA Retrofit Cost Analyzer (RCA) methodology and Sargent & Lundy Study (backup for RCA). Both EPA and S&L study available at https://www.epa.gov/airmarkets/retrofit-cost-analyzer.



Appendix B.5.i - Response Letter 6

April 29, 2022

Steven McNeece
Nevada Division of Environmental Protection
901 S. Stewart Street
Suite 4001
Reno, NV 89701

Re: Response to a Sixth Follow-up Request for Additional Information
Regional Haze Four Factor Analyses
NV Energy Tracy (FIN 0029) and Valmy (FIN A0375) Generating Stations

Mr. McNeece:

Per your email correspondence dated February 22, 2022, Sierra Pacific Power Company d/b/a NV Energy (NVE) hereby provides a response detailing Nevada Division of Environmental Protection (NDEP)'s most recent request for additional information regarding the Four Factor Analyses at both the Tracy and North Valmy Generating Stations. Per our recent emails and phone conversations, this response addresses the questions related to the comments that NDEP received from the National Park Service (NPS) on the draft State Implementation Plan (SIP) you prepared to address Regional Haze for the second decadal planning period. Included below are NVE's responses to the assertions about the cost and technical feasibility associated with additional controls for sulfur dioxide (SO2) emissions from the North Valmy Generating Station made by the NPS in Sections 4.1.4 and 4.1.6 of comments summary document that you provided to us on February 22, 2022. Additional information with respect to the comments made by the NPS in Section 4.1.3 of the summary document regarding other statutory factors specific to the North Valmy Station to be considered when developing the SIP is also provided below, as well as requested cost estimates not previously provided that incorporate the now-enforceable retirement dates into the useful life for controls at both Valmy and Tracy Generating Station.

Please note that this is the response to NDEP's sixth follow-up request for additional information, as NVE also provided responses to NDEP's first request for additional information in a letter dated July 8, 2020, as well as a second request for additional information in a letter dated January 15, 2021, a third request for additional information in a letter dated April 16, 2021, a fourth request for additional information in a letter dated May 7, 2021, and two responses to a fifth request for additional information in letters dated August 27, 2021, and October 11, 2021. This letter and attachment address NDEP's most recent questions and should be considered a sixth addendum to the previously submitted Four Factor Analyses dated March 13, 2020.

NVE appreciates the opportunity to work with NDEP in this endeavor. Please feel free to contact Sean Spitzer at (702) 402-5132 should you have any questions.

Sincerely,

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

Tracy Follow-up Response:

Control Cost Estimate Updates – as requested in email dated March 15, 2022:

> *(a)…We have updated cost figures for SCR on Unit 6 from your October 11, 2021 letter, but not for Dry Low NOx Combustors….the final $/ton figures for all controls considered should reflect the closure date. Can you please provide these new cost figures for us in your next response…?"*

(a) NVE Response:

As discussed via email dated April 25, 2022, NVE has recalculated the cost effectiveness of Dry Low NOx (DLN) Combustor control implementation on the Tracy Pinion Pine unit. Assuming a best-case scenario that DLN is installed by the end of 2022, the control would have a life of 9 years given the now-enforceable shutdown date of December 31, 2031. As such, the revised cost effectiveness table for this control is shown below:

Tracy Unit 6 (Pinon Pine #4) Cost Effectiveness of NOx controls

Dry Low NOx Combustor Conversion – 9 Year Life	
Description	**Cost**
Estimated Capital Cost ($)	$13,464,516
Annual Capital Recovery ($/yr)	$2,044,697
Annual Operating Cost (excl. capital recovery) ($/yr)	$680,000
Total Annual Costs ($/yr)	$2,724,697
Annual Emission Rate with Controls (Tons/yr)	78 tons/yr
NOx Emission Reduction (Tons/year)	135.0
Control Cost Effectiveness ($/Ton)	**$20,183**

Equipment life 9 years, interest rate 6.75%

Valmy Follow-up Response:

<u>Comments in Section 4.1.4 and 4.1.6 Regarding Additional SO2 Controls on North Valmy Units 1 and 2</u>

(a) The Sargent & Lundy (S&L) Dry Sorbent Injection study report contains outdated cost information

(a) <u>NVE Response</u>:

In their comments about the use of DSI to control SO2 emissions from Unit 1, the NPS asserts that the S&L study that NVE utilized to estimate the cost of replacing the existing DSI system is nearly 10 years old, and implies that this study may contain outdated information. They note that the EPA's <u>Control Cost Manual</u> (the <u>Manual</u>) recommends against using out of date cost information and assert that escalation of costs from a 10-year old study results in an inaccurate cost estimate.

NVE agrees with the general statement presented in Chapter 1, Section 2.5.3 of the <u>Manual</u> that the accuracy of an escalated cost estimate declines the longer the time period over which the escalation is done. Nonetheless, we respectfully disagree with the assertion that the information we supplied to you previously about the cost of converting the existing Unit 1 DSI system to a trona-based system is inaccurate for two reasons. First, as explained further below, the cost information we provided is the best information available because it was based on a site-specific cost estimate prepared by a leading power industry engineering firm for the purpose of assessing the costs associated with a trona-based DSI system on Unit 1. In addition, we note that in the <u>Manual,</u> EPA themselves have no hesitation in presenting emission control cost information that has been escalated beyond 10 years as accurate. To develop the equipment costs presented in the most recent (7th) edition of the <u>Manual</u>, EPA has generally taken the same cost information that was presented in the 6th edition (some of which was gathered in the late 1980s) and escalated it to current dollars using the same price indexing method and source of data (the Chemical Engineering Plant Cost Index) that we used to develop the cost estimates for emission controls at Valmy. In this regard, the methodology that we followed to develop these cost estimates is no less accurate than the methodology EPA used to develop the cost estimates presented in the <u>Manual</u>.

Finally, contrary to the assertion made by the NPS in Section 4.1.4 of the comments document, NVE is not aware of any significant technology improvements that have been made with DSI systems since the S&L study was completed in 2012.

(b) Sargent & Lundy's cost estimates are inflated and were prepared for a different purpose than for addressing Regional Haze

(b) <u>NVE Response</u>:

We disagree with the NPS assertion that cost estimates prepared by S&L are inaccurate because they contain cost elements that are not utilized in the methodology presented in the <u>Manual</u>. Cost estimates fall into several categories ranging from rough approximations to highly detailed and itemized accounts based on engineering plans and specifications. As explained in its Chapter 1, Section 2.3, the costs and estimating methodology presented in the <u>Manual</u> are for study level estimates. The cost estimate prepared by S&L, on the other hand, was a budgetary level estimate intended to be used to inform NVE's decision on a regulatory compliance pathway. As such, the S&L estimate has a more precise level of accuracy and contains estimates of costs that NVE would bear that are not included in the Manual's methodology.

Moreover, two of the cost elements of the S&L estimate that the NPS describes as being inappropriate (owner's costs and allowance for funds used during construction) are specifically included in the IPM model[1] that the NPS itself used to develop its own DSI cost estimates as documented in the worksheet provided.

As described above, among the goals of the 2012 S&L study was to assess the specific cost impact associated with using a trona-based DSI system to control SO2 emissions on Valmy Unit 1. While we agree that the regulatory driver for NVE to consider a trona-based system was the Mercury and Air Toxics Standards (MATS) for power plants, we believe it is irrelevant that this is a different regulatory program than the regional haze rule; the information presented and conclusions reached in the S&L study, particularly with respect to the cost of emission controls, are irrespective of any particular regulatory program.

(c) A milled trona-based DSI system can be cost-effectively retrofit onto North Valmy Unit 1

(c) NVE Response:

As NVE explained in the previously submitted response letter dated January 15, 2021, we recognize that DSI is a technically feasible means to control acid gas emissions like sulfur dioxide (SO2) from coal-fired power plants, and a DSI system employing hydrated lime has been used for nearly 7 years on North Valmy Unit 1. Although installed to comply with the HCl limitations in the MATS rule, the existing DSI system also provides a moderate level of SO2 control from the unit. Based on the sulfur content of the coal fired between 2015 and 2021 and the unit's actual SO2 emissions, the existing DSI system on North Valmy Unit 1 provides an average SO2 control efficiency of 22%.

As explained in our previously submitted response letter dated April 16, 2021, however, the existing DSI system on Unit 1 cannot be adapted to utilize milled trona. For trona to be used, the existing DSI system would need to be completely replaced; different and more extensive sorbent preparation, milling, and handling equipment would need to be installed. Provisions to also inject activated carbon would need to be provided to minimize the formation of a brown plume from the Unit 1 stack; the use of sodium-based sorbents has been shown to exacerbate the conversion of NO to NO2 causing visible plume formation. The information we provided previously, which again was based on a site-specific study conducted by S&L, is that replacing the existing system with a trona-based system would entail a capital cost of $37.4 MM (2019 cost basis).

The 2012 study that S&L conducted was specifically undertaken to evaluate whether sodium-based DSI systems (employing either trona or sodium bicarbonate) could be employed to meet the MATS limit for SO2 emissions on Valmy Unit 1. The cost estimates developed for that study are site-specific, and in this regard, NVE asserts that the cost estimate associated with the use of milled

[1] "IPM Model – Updates to Cost and Performance for APC Technologies: Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology", pg. 5 (April 2017)

trona we provided previously is more accurate than the generic cost estimate generated by the NPS ($17.7 MM, as summarized in Table 2 of Section 4.1.4).

Apart from the fact that the cost estimate we provided previously is site-specific and the estimate generated by the NPS is not, NVE notes that there are at least two other differences between these estimates. The NPS notes that the basis of their estimate is the "…method developed by S&L for EPA's Integrated Planning Model." In the paper describing development of this method[2], however, S&L states that their cost estimating methodology for the IPM model does not incorporate costs associated with activated carbon injection because they assume that coal-fired units already "…control NOx to a sufficiently low level that a brown plume should not be an issue with sodium-based DSI." Moreover, the NPS cost analysis presents a capital recovery cost for this alternative that appears to be based on a cost of capital of 4.72%. In our previously submitted response letter dated July 8, 2020, we explained why the cost of capital for NVE's operating utilities that is set by the Public Utility Commission of Nevada (6.75%) is the preferred firm-specific cost of capital for us to use when evaluating the economics of emissions control options. Consequently, NVE believes that the NPS estimates of both the capital cost of a trona-based DSI system for North Valmy as well as the annualized cost of that capital are understated.

Given that NVE has committed to retiring North Valmy Unit 1 at the end of 2028, the equipment life of a milled trona-based DSI system installed on the unit and operational by the end of 2024 would be 4 years. Based on the site-specific cost estimate prepared for us by S&L, the annual capital recovery cost for this system would be $10.99 MM per year and the total annualized cost would be $15.3 MM per year[3]. Using the projected Unit 1 output for 2028 (equal to the unit's 2016 – 2018 baseline output), the projected annual SO2 removal rate for this alternative at the MATS SO2 emission limit of 0.20 lb/MMBtu is 1,337 tons/yr. Thus, NVE estimates that the replacement of the existing hydrated lime-based DSI system with a milled trona-based DSI system would have an overall cost effectiveness of $11,409 per ton controlled. Compared to the current DSI system, the use of a milled trona-based system would control an additional 939 tons of SO2 per year for an incremental cost effectiveness of $16,254 per incremental ton removed.

For these reasons, NVE believes that it would not be cost effective to replace the existing hydrated lime-based DSI system on North Valmy Unit 1 with a DSI system that utilizes milled trona for the remaining useful life of the unit.

(d) A hydrated lime-based DSI system is a cost-effective means to control SO2 emissions from North Valmy Unit 1

(d) NVE Response:

In Table 2 of Section 4.1.4 of their comments summary document, the NPS presents an estimate of the capital and annual operating costs associated with replacing the existing hydrated lime-based DSI system on North Valmy Unit 1, and asserts that replacing the existing hydrated lime-based DSI system with a new system would be cost effective. NVE finds this comment to be confusing because Unit 1 is already equipped with a hydrated lime based DSI system. That

[2] "IPM Model – Updates to Cost and Performance for APC Technologies: Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology," pg. 3 (April 2017)

[3] See the attachment to this letter for additional detail on the estimated cost to replace the existing DSI system on Unit 1, assuming a useful life of 4 years that accounts for the 2028 shutdown commitment of the unit

system was installed less than seven years ago, and there is no technical or economic reason to replace this existing system. Moreover, the NPS cost estimate assumes that a hydrated lime-based DSI system would achieve 50% removal of SO2. Based on our existing system's performance, however, this technology achieves a much lower level of SO2 control (22%) as noted above.

(e) Modern Flue Gas Desulfurization (FGD) systems achieve better than 95% control of SO2 emissions

(e) NVE Response:

NPS states in Section 4.1.4 of the comments summary document that modern FGD systems "regularly" achieve better than 95% control of SO2. NVE agrees that this statement may be true for certain types of new FGD systems, but disagrees with the assertion that upgrading the existing FGD system on North Valmy Unit 2 would be cost effective. As we explained in our letter dated January 15, 2021, the performance of the existing FGD system on Unit 2 has already been fully optimized; the system was designed to achieve 70% SO2 removal but now achieves at least 78% removal. As explained below, further improvement of the performance of this system would require that the existing multi-nozzle spray dryer vessels would need to be reconfigured to single nozzle spray dryer vessels in order to achieve any additional improvement in the control of SO2. As shown below, this alternative would not be cost effective considering the commitment to retire this unit at the end of 2028.

(f) A detailed four-factor analysis for upgrading the existing lime-based FGD system on North Valmy Unit 2 should be conducted

(f) NVE Response:

Identification of control options – The existing lime spray dryer based FGD system on North Valmy Unit 2 consists of three spray dryer absorber vessels operating in parallel. Each vessel is equipped with three separate lime slurry atomizers that spray reagent near the top of the vessel in an overlapping pattern that contacts the flue gas from the unit in a counter-current fashion. As noted above and in our previous submittal dated January 15, 2021, this existing system has already been optimized to the extent possible by using the highest quality lime commercially available, by using recycled system ash as well as fresh lime to increase the available reagent surface area, by operating at the lowest feasible saturation approach temperature, and by optimizing the spray coverage available with the multi-nozzle configuration. The only technically feasible alternative to further improve the SO2 control efficiency of this system would entail replacement of the existing multi-nozzle atomizer system in each vessel with a single nozzle design that would provide nearly 100% spray coverage across the flue gas flow pattern.

Cost of controls – A detailed engineering study of the technical and economic feasibility of retrofitting the existing multi-nozzle atomizer-based FGD system on Unit 2 with a single nozzle-based system has not been conducted. Nonetheless, in 2013 NVE received budgetary cost information for the principal equipment that would be required to implement this alternative from the vendor of this equipment, Babcock & Wilcox (B&W).

As shown in the attached cost estimate, the estimated capital cost of retrofitting the existing multi-atomizer spray dryers with single atomizer systems is over $46 MM. The total annualized cost of this alternative, assuming that it would be operational by the end of 2024, is estimated at over $17 MM per year. At an estimated SO2 control efficiency of 94%, this alternative would control a total 2,141 tons/yr based on the projected output of Unit 2 in 2028. Thus, the overall cost effectiveness of this alternative is about $8,000 per ton controlled. Compared to the current FGD system on Unit 2, this alternative would control an additional 364.4 tons/yr; in this regard, the system retrofit would have an incremental cost effectiveness of over $46,500 per additional ton removed.

Time necessary to install such controls – As noted above, an engineering study of this option has not been conducted, so a detailed schedule to retrofit the existing spray dryer vessels to a single atomizer configuration has not been assessed. The work would need to take place, however, with Unit 2 removed from service. As described further below, a previous engineering study conducted to evaluate the feasibility of installing an FGD system on Unit 1 concluded that it would take 46 months from project initiation to commercial operation for a project of this magnitude. The cost effectiveness figures presented above assume that this alternative would have a useful life of four years, which would necessitate that the upgraded FGD system be commercially operational by the end of 2024, or within about 32 months from now. In NVE's opinion, this would be an unrealistically short timeframe for a project of this size and complexity.

Energy and non-air quality impacts associated with installing controls – Improving the SO2 control efficiency of the FGD system on Unit 2 would result in a greater quantity of solid waste being generated and needing to be landfilled compared to the current system. The increase in solid waste generation is estimated at over 1,700 tons per year. As noted below, this increased quantity of solid waste would need to be managed in conformance with the Coal Combustion Residuals rule.

Remaining useful life of the facility – NVE has committed to the retirement of the North Valmy Station by the end of 2028. In this regard, the overall remaining useful life of Unit 2 is just over 6 ½ years. Considering the estimated time needed to retrofit the existing system with new atomizers, the useful life of the upgraded FGD system may only be as long as four years.

Conclusion – The only available option to upgrade the existing FGD system on North Valmy Unit 2 is to retrofit the three existing multi-atomizer spray dryer vessels to a single atomizer configuration. This would entail a complicated and expensive equipment change that is estimated to cost over $46 MM and have an overall cost effectiveness impact of around $8,000 per ton removed. Compared to the current FGD system, the upgraded system would have an incremental cost effectiveness of at least $46,000 per additional ton removed. In NVE's opinion, these significant cost impacts are not warranted considering the relatively modest reduction in SO2 emissions that could be achieved and the relatively short remaining life of the facility.

Comments in Section 4.1.3 Evaluation of Clean Air Act Statutory Factors at North Valmy

(a) The remaining useful life for additional emission controls at North Valmy is five years

(a) NVE Response

Considering that NVE has committed to retiring both units at North Valmy by December 31, 2028, a five year useful life would dictate that any additional emission controls on either unit would need be operational by December 31, 2023, or 20 months from now. As noted above, we estimate that it would take several years to install additional controls on these units. Considering the significant cost impact that new emission controls would require, we believe it would be imprudent to our ratepayers for us to begin the process of installing controls on these units until the SIP that would require such controls has been approved. Accordingly, NVE believes the NPS estimate of five years of useful life for any new emission control technologies is overstated.

(b) Dry Sorbent Injection and scrubber upgrades can be installed on North Valmy Units 1 and 2 in less than two years

(b) NVE Response

In NVE's first Four Factor submittal for the North Valmy Station dated March 13, 2020, we estimated based on our previous experience that it might take up to six years to install additional emission controls following SIP approval given the number, range, and complexity of retrofit issues at the facility. In particular, in a study to evaluate the option of installing a FGD system on Unit 1, S&L estimated that it would take 46 months to go from project authorization to commercial operation. To estimate the cost effectiveness of alternative emission controls in this current submittal, we have assumed that any new controls would be in place and operational by the end of 2024 (about 2 ½ years from now) thereby providing four years of useful life prior to the Station shutdown date to which we have committed. Further engineering studies would need to be conducted to assess the validity of this assumption, but based on our prior experience, NVE respectfully disagrees with the NPS's estimated installation schedule for these technologies.

(c) No unique or unusual non-air quality impacts exist at North Valmy in conjunction with additional SO2 control measures on Units 1 and 2

(c) NVE Response:

This assertion is not accurate. NVE has repeatedly stated in our previous submittals (see letters dated March 13, 2020, and April 16, 2021) that using either a trona based DSI system on Unit 1 or increasing the Calcium:Sulfur ratio in the FGD system on Unit 2 would create additional solid waste that would need to be disposed of in conformance with the Coal Combustion Residuals rule. This presents additional facility handling and disposal costs as well as non-air environmental impacts associated with the facility's landfill.

Control Cost Estimate Updates – as requested in email dated March 15, 2022:

(a)… for updated Valmy costs, where SNCR on both units and DSI for Unit 1 is provided in your August 27, 2021 letter, but new cost figures weren't provided for SCR on both units and FGD systems on Unit 1 to reflect the shorter life resulting from the closure date. ….the final \$/ton figures for all controls considered should reflect the closure date. Can you please provide these new cost figures for us in your next response…?"

(a) NVE Response:

Finally, in response to your request, provided in the attachment to this letter are updated cost estimates for Selective Catalytic Reduction (SCR) systems for North Valmy Units 1 and 2, as well as FGD controls on Unit 1, considering NVE's commitment to retire both units by the end of 2028. Further detail regarding the DSI costs on Unit 1 and FGD upgrade costs on Unit 2 have also been provided.

APPENDIX A

Revised Cost Effectiveness Tables for Valmy

North Valmy Generating Station
Cost and Emissions Comparison - Change in Equipment Life

Projection:	May 2021 Response to NDEP Comments	April 2022 Response to NDEP Comments
	Input Data	
Projected Future Annual Output (MWhrs)		
Unit 1	466,437	466,437
Unit 2	575,835	575,835
Base year for equipment costs	2019	2019
Interest rate used for capital recovery	6.75%	6.75%
Equipment life (years)	20	4
North Valmy Unit 1		
SELECTIVE CATALYTIC REDUCTION FOR NOx CONTROL		
Estimated Capital Cost	$126.7 million	$126.7 million
Estimated Annualized Capital Cost	$11.73 million/yr	$37.21 million/yr
Estimated Annual O&M Cost	$1.99 million/yr	$1.99 million/yr
Estimated Total Annual Cost	$13.72 million/yr	$39.19 million/yr
Uncontrolled NOx Emissions	804 tons/yr	804 tons/yr
NOx Emission Reduction with SCR	681 tons/yr	681 tons/yr
Control Cost Effectiveness	$20,168/ton	$57,583/ton
TRONA-BASED DRY SORBENT INJECTION FOR SO2 CONTROL		
Estimated Capital Cost	$37.4 million	$37.4 million
Estimated Annualized Capital Cost	$3.47 million/yr	$10.99 million/yr
Estimated Annual O&M Cost	$4.27 million/yr	$4.27 million/yr
Estimated Total Annual Cost	$7.74 million/yr	$15.26 million/yr
Uncontrolled SO2 Emissions	1,812 tons/yr	1,812 tons/yr
SO2 Emission Reduction with Lime DSI	1,338 tons/yr	1,338 tons/yr
Control Cost Effectiveness	$5,786/ton	$11,409/ton
LIMESTONE BASED FLUE GAS DESULFURIZATION FOR SO2 CONTROL		
Estimated Capital Cost	$247.8 million	$247.8 million
Estimated Annualized Capital Cost	$22.95 million/yr	$72.76 million/yr
Estimated Annual O&M Cost	$3.75 million/yr	$3.75 million/yr
Estimated Total Annual Cost	$26.70 million/yr	$76.51 million/yr
Uncontrolled SO2 Emissions	1,812 tons/yr	1,812 tons/yr
SO2 Emission Reduction with Limestone FGD	1,751 tons/yr	1,751 tons/yr
Control Cost Effectiveness	$15,250/ton	$43,704/ton
LIME BASED FLUE GAS DESULFURIZATION FOR SO2 CONTROL		
Estimated Capital Cost	$238.2 million	$238.2 million
Estimated Annualized Capital Cost	$22.06 million/yr	$69.95 million/yr
Estimated Annual O&M Cost	$3.82 million/yr	$3.82 million/yr
Estimated Total Annual Cost	$25.88 million/yr	$73.77 million/yr
Uncontrolled SO2 Emissions	1,812 tons/yr	1,812 tons/yr
SO2 Emission Reduction with Lime FGD	1,751 tons/yr	1,751 tons/yr
Control Cost Effectiveness	$14,782/ton	$42,135/ton
North Valmy Unit 2		
SELECTIVE CATALYTIC REDUCTION FOR NOx CONTROL		
Estimated Capital Cost	$147.2 million	$147.2 million
Estimated Annualized Capital Cost	$13.63 million/yr	$43.22 million/yr
Estimated Annual O&M Cost	$2.34 million/yr	$2.34 million/yr
Estimated Total Annual Cost	$15.97 million/yr	$45.56 million/yr
Uncontrolled NOx Emissions	1,002 tons/yr	1,002 tons/yr
NOx Emission Reduction with SCR	841 tons/yr	841 tons/yr
Control Cost Effectiveness	$18,989/ton	$54,178/ton

NV Energy - North Valmy Unit 1
Estimated Lime Flue Gas Desulfurization System Cost

Input data

Escalation Indexes	2009	2019
Plant Cost (1)	521.9	609.7
Labor (2)	111.3	136.2
Raw Materials (3)	255.0	277.2

Annualization Data		
Equipment Life	4	years
Interest Rate	6.75	%
Capital Recovery Factor	0.2936	
Full Load Output	237	net MW
Heat rate	10.175	MMBtu/net MW
Projected Output (2028)	466,437.0	MWhr
	22.5%	of full capacity
Projected Heat Input (2028)	4,745,996	MMBtu/yr
Uncontrolled SO2 Emissions (2016 - 2018 avg)	1,812.3	ton/yr
Proj. Uncontrolled SO2 Emisions (2028)	1,812.3	ton/yr
	0.76	lb/MMBtu
FGD Removal Efficiency	96.6	%
Controlled SO2 Projected Emissions (2028)	61.6	ton/yr
Projected SO2 Removal (2028)	1,750.7	ton/yr
Reagent Stoichiometric Ratio	1.03	
Reagent requirement (2028)	2,085.0	ton/yr
Reagent cost, 2009	150	$/ton
Reagent cost, 2028	163	$/ton
Waste produced	3.41	ton/ton SO2 removed
	5,969.0	ton waste/yr
Waste disposal cost	10	$/ton
Auxiliary power requirement at full load	4,740.0	kW
Aux power requirement at 2028 load	1,064.9	kW
	9,328.7	MWhr/yr
Auxiliary power cost	50	$/MWhr
Water requirement at full load	433,440	gal/day
Water requirement at 2028 load	97,380	gal/day
	35,544	1000 gal/yr
Water cost	0.4	$/1000 gal

Notes:
1 - Chemical Engineering Plant Cost Index (1957 - 1959 = 100)
2 - Bureau of Labor Statistics Employment Cost Index - Construction Labor (2005 = 100)
3 - Bureau of Labor Statistics Producer Price Index - Basic Inorganic Chemicals

Cost Estimate - Lime FGD System

	S&L Study (2009 $)				Current Estimate (2021 $)			
	Equipment	Material	Labor	Total	Equipment	Material	Labor	Total
DIRECT COSTS								
Site Work	$75,000	$7,309,100	$6,373,100	$13,757,200	$87,600	$8,538,700	$7,798,900	$16,425,200
Lime Handling System	$235,000	$1,496,600	$1,937,200	$3,668,800	$274,500	$1,748,400	$2,370,600	$4,393,500
FGD System - OEM Scope of Supply	$26,500,000	$619,300	$17,442,700	$44,562,000	$30,958,100	$723,500	$21,345,000	$53,026,600
Reagent Preparation	$0	$2,401,600	$5,109,500	$7,511,100	$0	$2,805,600	$6,252,600	$9,058,200
Absorber System	$621,000	$2,817,100	$3,787,200	$7,225,300	$725,500	$3,291,000	$4,634,500	$8,651,000
Dewatering System	$0	$1,655,600	$2,100,600	$3,756,200	$0	$1,934,100	$2,570,500	$4,504,600
Gypsum Handling & Loadout System	$985,000	$42,800	$401,100	$1,428,900	$1,150,700	$50,000	$490,800	$1,691,500
Demolition	$0	$125,000	$220,600	$345,600	$0	$146,000	$270,000	$416,000
Flue Gas System	$105,000	$1,422,300	$2,376,200	$3,903,500	$122,700	$1,661,600	$2,907,800	$4,692,100
Chimney	$20,000	$6,785,000	$10,438,000	$17,243,000	$23,400	$7,926,500	$12,773,200	$20,723,100
Wastewater treatment	$8,000	$61,200	$58,900	$128,100	$9,300	$71,500	$72,100	$152,900
Piping and Misc Equipment	$300,000	$1,290,300	$2,018,000	$3,608,300	$350,500	$1,507,400	$2,469,500	$4,327,400
Fire Protection, Detection & Alarm	$0	$560,000	$891,600	$1,451,600	$0	$654,200	$1,091,100	$1,745,300
Control & Instrumentation	$2,275,800	$70,100	$652,600	$2,998,500	$2,658,700	$81,900	$798,600	$3,539,200
Electrical	$2,052,500	$493,600	$1,377,000	$3,923,100	$2,397,800	$576,600	$1,685,100	$4,659,500
Scaffolding	$0	$500,000	$473,400	$973,400	$0	$584,100	$579,300	$1,163,400
Construction Equipment Supplement	$0	$1,200,000	$485,000	$1,685,000	$0	$1,401,900	$593,500	$1,995,400
SUBTOTAL - DIRECT COSTS	$33,177,300	$28,849,600	$56,142,700	$118,169,600	$38,758,800	$33,703,000	$68,703,100	$141,164,900
INDIRECT COSTS								
Construction Indirect Cost	$165,900	$5,914,200	$28,262,300	$34,342,400	$193,800	$6,909,200	$34,585,100	$41,688,100
Total Direct and Construction Indirect (D&CI)	$33,343,200	$34,763,800	$84,405,000	$152,512,000	$38,952,600	$40,612,200	$103,288,200	$182,853,000
Engineering, Procurement & Project Services		7% of D&CI		$10,675,800				$12,799,700
Construction Management/Field Engineering		2% of D&CI		$3,050,200				$3,657,100
Startup and Commissioning		1% of D&CI		$1,525,100				$1,828,500
Owner's Cost		3% of D&CI + other indirects		$5,032,900				$6,034,100
SUBTOTAL - INDIRECT COSTS				$54,626,400				$66,007,500
CONTINGENCY		15% of Direct and Indirect Costs		$25,919,400				$31,075,900
TOTAL CAPITAL COST				$198,715,400				$238,248,300
ANNUALIZED CAPITAL, OPERATING AND MAINTENANCE COST								
Annualized Capital Cost								$69,949,700
Variable O&M Cost								
FGD Disposal Cost								$59,700
Lime Reagent Cost								$339,900
Auxiliary Power Cost								$466,400
Water Cost								$14,200
Total								$880,200
Fixed O&M Cost								
Operating Labor		12 operators @$45/hr, 40 hrs/wk						$1,123,200
Maintenance Materials		Per S&L study						$1,088,000
Mantainance Labor		Per S&L study						$726,000
Total								$2,937,200
TOTAL ANNUALIZED CAPITAL, OPERATING AND MAINTENANCE COST								$73,767,100
Cost Effectiveness ($/ton controlled)								$42,135

NV Energy - North Valmy Unit 1
Estimated Limestone Flue Gas Desulfurization System Cost

Input data

Escalation Indexes	2009	2019
Plant Cost (1)	521.9	609.7
Labor (2)	111.3	136.2
Raw Materials (3)	255.0	277.2

Annualization Data		
Equipment Life	4	years
Interest Rate	6.75	%
Capital Recovery Factor	0.2936	
Full Load Output	237	net MW
Heat rate	10.175	MMBtu/net MW
Projected Output (2028)	466,437.0	MWhr
	22.5%	of full capacity
Projected Heat Input (2028)	4,745,996	MMBtu/yr
Uncontrolled SO2 Emissions (2016 - 2018 avg)	1,812.3	ton/yr
Proj. Uncontrolled SO2 Emisions (2028)	1,812.3	ton/yr
	0.76	lb/MMBtu
FGD Removal Efficiency	96.6	%
Controlled SO2 Projected Emissions (2028)	61.6	ton/yr
Projected SO2 Removal (2028)	1,750.7	ton/yr
Reagent Stoichiometric Ratio	1.03	
Reagent requirement (2028)	2,817.6	ton/yr
Reagent cost, 2009	50	$/ton
Reagent cost, 2028	54	$/ton
Waste produced	3.31	ton/ton SO2 removed
	5,799.9	ton waste/yr
Waste disposal cost	10	$/ton
Auxiliary power requirement at full load	5,214.0	kW
Aux power requirement at 2028 load	1,171.4	kW
	10,261.6	MWhr/yr
Auxiliary power cost	50	$/MWhr
Water requirement at full load	498,240	gal/day
Water requirement at 2028 load	111,938	gal/day
	40,858	1000 gal/yr
Water cost	0.4	$/1000 gal

Notes:
1 - Chemical Engineering Plant Cost Index (1957 - 1959 = 100)
2 - Bureau of Labor Statistics Employment Cost Index - Construction Labor (2005 = 100)
3 - Bureau of Labor Statistics Producer Price Index - Basic Inorganic Chemicals

Cost Estimate - Limestone FGD System

	S&L Study (2009 $)				Current Estimate (2021 $)			
	Equipment	Material	Labor	Total	Equipment	Material	Labor	Total
DIRECT COSTS								
Site Work	$75,000	$7,510,700	$6,459,700	$14,045,400	$87,600	$8,774,200	$7,904,900	$16,766,700
Limestone Handling System	$3,544,400	$966,400	$2,480,300	$6,991,100	$4,140,700	$1,129,000	$3,035,200	$8,304,900
FGD System - OEM Scope of Supply	$27,500,000	$619,300	$17,442,700	$45,562,000	$32,126,400	$723,500	$21,345,000	$54,194,900
Reagent Preparation	$0	$2,401,600	$5,420,400	$7,822,000	$0	$2,805,600	$6,633,100	$9,438,700
Absorber System	$621,000	$2,817,100	$3,787,200	$7,225,300	$725,500	$3,291,000	$4,634,500	$8,651,000
Dewatering System	$0	$1,655,600	$2,100,600	$3,756,200	$0	$1,934,100	$2,570,500	$4,504,600
Gypsum Handling & Loadout System	$985,000	$42,800	$401,100	$1,428,900	$1,150,700	$50,000	$490,800	$1,691,500
Demolition	$0	$125,000	$220,600	$345,600	$0	$146,000	$270,000	$416,000
Flue Gas System	$105,000	$1,422,300	$2,376,200	$3,903,500	$122,700	$1,661,600	$2,907,800	$4,692,100
Chimney	$20,000	$6,785,000	$10,438,000	$17,243,000	$23,400	$7,926,500	$12,773,200	$20,723,100
Wastewater treatment	$8,000	$61,200	$58,900	$128,100	$9,300	$71,500	$72,100	$152,900
Piping and Misc Equipment	$300,000	$1,290,300	$2,018,000	$3,608,300	$350,500	$1,507,400	$2,469,500	$4,327,400
Fire Protection, Detection & Alarm	$0	$785,000	$1,172,400	$1,957,400	$0	$917,100	$1,434,700	$2,351,800
Control & Instrumentation	$2,395,800	$70,100	$678,200	$3,144,100	$2,798,800	$81,900	$829,900	$3,710,600
Electrical	$2,052,500	$493,600	$1,377,000	$3,923,100	$2,397,800	$576,600	$1,685,100	$4,659,500
Scaffolding	$0	$500,000	$473,400	$973,400	$0	$584,100	$579,300	$1,163,400
Construction Equipment Supplement	$0	$1,200,000	$485,000	$1,685,000	$0	$1,401,900	$593,500	$1,995,400
SUBTOTAL - DIRECT COSTS	$37,606,700	$28,746,000	$57,389,700	$123,742,400	$43,933,400	$33,582,000	$70,229,100	$147,744,500
INDIRECT COSTS								
Construction Indirect Cost	$188,000	$5,892,900	$28,895,100	$34,976,000	$219,600	$6,884,300	$35,359,500	$42,463,400
Total Direct and Construction Indirect (D&CI)	$37,794,700	$34,638,900	$86,284,800	$158,718,400	$44,153,000	$40,466,300	$105,588,600	$190,207,900
Engineering, Procurement & Project Services		7% of D&CI		$11,110,300				$13,314,600
Construction Management/Field Engineering		2% of D&CI		$3,174,400				$3,804,200
Startup and Commissioning		1% of D&CI		$1,587,200				$1,902,100
Owner's Cost		3% of D&CI + other indirects		$5,237,700				$6,276,900
SUBTOTAL - INDIRECT COSTS				$56,085,600				$67,761,200
CONTINGENCY		15% of Direct and Indirect Costs		$26,974,200				$32,325,900
TOTAL CAPITAL COST				$206,802,200				$247,831,600

ANNUALIZED CAPITAL, OPERATING AND MAINTENANCE COST

Annualized Capital Cost		$72,763,400
Variable O&M Cost		
FGD Disposal Cost		$58,000
Limestone Reagent Cost		$152,100
Auxiliary Power Cost		$513,100
Water Cost		$16,300
Total		$739,500
Fixed O&M Cost		
Operating Labor	12 operators @$45/hr, 40 hrs/wk	$1,123,200
Maintenance Materials	Per S&L study	$1,132,000
Mantainance Labor	Per S&L study	$755,000
Total		$3,010,200
TOTAL ANNUALIZED CAPITAL, OPERATING AND MAINTENANCE COST		$76,513,100
Cost Effectiveness ($/ton controlled)		$43,704

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? Coal

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. 1.30

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

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? 10,557 Btu/lb

What is the estimated actual annual MWhs output? 466,437 MWh net

Enter the net plant heat input rate (NPHR) 10.175 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

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous

Enter the sulfur content (%S) = 0.45 percent by weight

For units burning coal blends:

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	0.3368	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0500	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.100	

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	4	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 temperature, if known.

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	2019		
CEPCI for 2019	609.7	Enter the CEPCI value for 2019	541.7 2016 CEPCI
Annual Interest Rate (i)	6.8	Percent	
Reagent ($Cost_{reag}$)	0.950	$/gallon for 19% ammonia	
Electricity ($Cost_{elect}$)	0.0754	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/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 Jan-21

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* 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 https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the 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/.		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	11,841	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/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/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 =	2,414	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	2,078,102	MWh net
Estimated Actual Annual MWhs Output (Boutput) =		466,437	MWh net
Heat Rate Factor (HRF) =	NPHR/10 =	1.02	
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) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	85.2	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	692.29	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	680.59	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.06	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	1,117,926	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	109.48	/hour
Residence Time	$1/V_{space}$	0.55	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 =	< 3	lbs/MMBtu
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	1.30	

* 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	0.3118	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x Slipadj x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	10,211.14	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	1,165	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 $A_{catalyst}$	1,339	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	36.6	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	53	feet

Reagent Data:

Type of reagent used: Ammonia

Molecular Weight of Reagent (MW) = 17.03 g/mole

Density = 58 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	282	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,484	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	191	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	64,300	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	0.2936

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	1338.42	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$84,096,980	in 2019 dollars
Reagent Preparation Cost (RPC) =	$4,233,032	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$9,122,196	in 2019 dollars
Total Capital Investment (TCI) =	$126,687,871	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$84,096,980	in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$4,233,032	in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0	in 2019 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 (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$9,122,196	in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$1,984,091	in 2019 dollars
Indirect Annual Costs (IDAC) =	$37,206,373	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$39,190,464	in 2019 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 =	$633,439	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$357,392	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$198,424	in 2019 dollars
Annual Catalyst Replacement Cost =		$794,835	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.	
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$1,984,091	in 2019 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) =	$10,814	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$37,195,559	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$37,206,373	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$39,190,464	per year in 2019 dollars
NOx Removed =	681	tons/year
Cost Effectiveness =	$57,583	per ton of NOx removed in 2019 dollars

Data Inputs

SCR Cost Estimate - North Valmy Unit 2

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? Utility

What type of fuel does the unit burn? Coal

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. 1.30

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

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?	10,557	Btu/lb
What is the estimated actual annual MWhs output?	575,835	MWh net
Enter the net plant heat input rate (NPHR)	10.949	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

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous

Enter the sulfur content (%S) = 0.45 percent by weight

For units burning coal blends:

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	0.3168	lb/MMBtu
Outlet NO_x Emissions (NOx_{out}) from SCR	0.0500	lb/MMBtu
Stoichiometric Ratio Factor (SRF)	1.100	

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	4	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 temperature, if known.

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	2019		
CEPCI for 2019	609.7	Enter the CEPCI value for 2019	541.7 2016 CEPCI
Annual Interest Rate (i)	6.75	Percent	
Reagent ($Cost_{reag}$)	0.950	$/gallon for 19% ammonia	
Electricity ($Cost_{elect}$)	0.0754	$/kWh	
Catalyst cost ($CC_{replace}$)	227.00	$/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 — Jan-21

* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* 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 https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the 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/.		Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Higher Heating Value (HHV) (Btu/lb)	11,841	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/.		Fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/electricity/data/eia923/.
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.		Check with vendors for current prices.
Operator Labor Rate ($/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 =	2,891	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	2,313,076	MWh net
Estimated Actual Annual MWhs Output (Boutput) =		575,835	MWh net
Heat Rate Factor (HRF) =	NPHR/10 =	1.09	
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) =	$(NOx_{in} - NOx_{out})/NOx_{in}$ =	84.2	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	771.28	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	841.00	tons/year
NO_x removal factor (NRF) =	EF/80 =	1.05	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	1,339,030	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst}$ =	111.15	/hour
Residence Time	$1/V_{space}$	0.54	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 =	$(\%S/100)x(64/32)*1x10^6)/HHV$ =	< 3	lbs/MMBtu
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	1.30	

* 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)$(1/((1+ \text{interest rate})^Y -1)$, where Y = $H_{catalyts}/(t_{SCR}$ x 24 hours) rounded to the nearest integer	0.3118	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})	12,047.24	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	1,395	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 $A_{catalyst}$	1,604	ft^2
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	40.1	feet
Reactor height =	$(R_{layer} + R_{empty})$ x (7ft + h_{layer}) + 9ft	53	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 $MW_R)/MW_{NOx}$ =	314	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/Csol =	1,653	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	221	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	74,200	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	0.2936

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	1537.49	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	$99,065,895	in 2019 dollars
Reagent Preparation Cost (RPC) =	$4,348,937	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2019 dollars
Balance of Plant Costs (BPC) =	$9,840,513	in 2019 dollars
Total Capital Investment (TCI) =	$147,231,949	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310{,}000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =	$99,065,895 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564{,}000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564{,}000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$4,348,937 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69{,}000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69{,}000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	$0 in 2019 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 (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529{,}000 \times (B_{MW} \times HRFx\ CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529{,}000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =	$9,840,513 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$2,324,139	in 2019 dollars
Indirect Annual Costs (IDAC) =	$43,239,347	in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$45,563,486	in 2019 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 =	$736,160	in 2019 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$457,397	in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$252,812	in 2019 dollars
Annual Catalyst Replacement Cost =		$877,771	in 2019 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.			
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}/R_{layer}$) x FWF	* Calculation Method 2 selected.	
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 35.3		
Direct Annual Cost =		$2,324,139	in 2019 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) =	$12,047	in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$43,227,300	in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$43,239,347	in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$45,563,486	per year in 2019 dollars
NOx Removed =	841	tons/year
Cost Effectiveness =	$54,178	per ton of NOx removed in 2019 dollars

NV Energy - North Valmy Unit 1
Estimated Trona-based Dry Sorbent Injection System Cost

Input data

Escalation Indexes	2012	2019	
Plant Cost (1)	584.6	609.7	
Labor (2)	116.3	136.2	
Raw Materials (3)	279.6	277.2	
Annualization Data			
Equipment Life	4	years	(Jan 2024 - Dec 2028)
Interest Rate	6.75	%	
Capital Recovery Factor	0.2936		
Full Load Output	237	net MW	
Heat rate	10.175	MMBtu/net MW	
Projected Output (2028)	466,437.0	MWhr	
	22.5%	of full capacity	
Projected Heat Input (2028)	4,745,996	MMBtu/yr	
Uncontrolled SO2 Emissions (2016 - 2018 avg)	1,812.3	ton/yr	
	0.76	lb/MMBtu	
DSI Design Emission Rate	0.20	lb/MMBtu	
DSI Removal Efficiency	73.8	%	
Controlled SO2 Baseline Emissions (2016 - 2018)	474.7	ton/yr	
Baseline SO2 Removal (2016 - 2018)	1,337.7	ton/yr	
Controlled SO2 Projected Emissions (2028)	474.7	ton/yr	
Projected SO2 Removal (2028)	1,337.7	ton/yr	
Trona Feed Ratio	5.72	lb reagent/lb SO2 removed	
Trona requirement (2028)	7,646.6	ton/yr	
Trona cost, 2012	167	$/ton	
Trona cost, 2028	166	$/ton	
PAC feed rate	200	lb/hr	
PAC requirement (2028)	876.0	ton/yr	
PAC cost, 2012	2200	$/ton	
PAC cost, 2028	2181	$/ton	
Waste produced			
Trona	0.81	lb/lb feed	
PAC	200	lb/hr	
Total	7,078	ton waste/yr	
Waste disposal cost	30	$/ton	
Auxiliary power requirement at full load	900.0	kW	
Aux power requirement at 2028 load	202.2	kW	
	1,771.3	MWhr/yr	
Auxiliary power cost	50	$/MWhr	

Notes:
1 - Chemical Engineering Plant Cost Index (1957 - 1959 = 100)
2 - Bureau of Labor Statistics Employment Cost Index - Construction Labor (2005 = 100)
3 - Bureau of Labor Statistics Producer Price Index - Basic Inorganic Chemicals

Cost Estimate - Limestone FGD System

	S&L Study (2012 $)				Current Estimate (2019 $)			
	Equipment	Material	Labor	Total	Equipment	Material	Labor	Total
DIRECT COSTS								
Demolition	$0	$30,000	$83,845	$113,845	$0	$31,300	$98,200	$129,500
Civil Work	$0	$63,500	$63,182	$126,682	$0	$66,200	$74,000	$140,200
Concrete	$0	$196,418	$400,560	$596,978	$0	$204,900	$469,100	$674,000
Steel	$0	$199,100	$201,501	$400,601	$0	$207,600	$236,000	$443,600
Architectural	$0	$300,900	$258,489	$559,389	$0	$313,800	$302,700	$616,500
Painting & Coating	$0	$12,500	$52,932	$65,432	$0	$13,000	$62,000	$75,000
Mechanical Equipment	$6,303,242	$165,000	$4,017,555	$10,485,797	$6,573,900	$172,100	$4,705,000	$11,451,000
Piping	$0	$142,198	$657,149	$799,347	$0	$148,300	$769,600	$917,900
Electrical Equipment	$616,500	$191,611	$352,438	$1,160,549	$643,000	$199,800	$412,700	$1,255,500
Raceway, Cable Tray & Conduit	$0	$332,489	$940,693	$1,273,182	$0	$346,800	$1,101,700	$1,448,500
Cable	$0	$170,985	$751,517	$922,502	$0	$178,300	$880,100	$1,058,400
Control & Instrumentation	$362,500	$100,000	$81,170	$543,670	$378,100	$104,300	$95,100	$577,500
SUBTOTAL - DIRECT COSTS	$7,282,242	$1,904,701	$7,861,031	$17,047,974	$7,595,000	$1,986,400	$9,206,200	$18,787,600
OTHER CAPITAL COSTS								
Construction Indirect Cost	$7,000			$7,000	$7,300	$0	$0	$7,300
Other Direct & Construction Indirect Costs				$6,462,000				$7,121,400
Indirect Costs				$1,764,000				$1,944,000
SUBTOTAL - INDIRECT COSTS				$8,233,000				$9,072,700
CONTINGENCY				$4,246,000				$4,679,300
OWNER'S COST				$4,429,000				$4,880,900
TOTAL CAPITAL COST				$33,955,974				$37,420,500

ANNUALIZED CAPITAL, OPERATING AND MAINTENANCE COST

Annualized Capital Cost		$10,986,700
Variable O&M Cost		
Waste Disposal Cost		$212,300
Trona Cost		$1,269,300
PAC Cost		$1,910,600
Auxiliary Power Cost		$88,600
Total		$3,480,800
Fixed O&M Cost		
Operating Labor	4 operators @$60/hr, 40 hrs/wk	$499,200
Maintenance Materials	Per S&L study	$118,000
Mantainance Labor	Per S&L study	$177,000
Total		$794,200
TOTAL ANNUALIZED CAPITAL, OPERATING AND MAINTENANCE COST		$15,261,700
Overall Cost Effectiveness ($/ton controlled)		$11,409

Existing hydrated lime-based DSI system control eff:	22%	
Projected 2028 SO2 emissions with existing system:	1,413.6	ton/yr
2028 SO2 controlled emissions with existing system:	398.7	ton/yr
Additional SO2 control achieved with milled trona:	938.9	ton/yr
Incremental Cost Effectiveness ($/ton controlled)		$16,254

NV Energy - North Valmy Unit 2
Estimated Cost to Upgrade Multi-Nozzle Spray Dryer System to Single Nozzle System

Input data

Plant Cost Escalation Index (1)			
2013	567.3		
2022	772.5		
Annualization Data			
Equipment Life	4	years	(Jan 2025 - Dec 2028)
Interest Rate	6.75	%	
Capital Recovery Factor	0.2936		
Full Load Output	264	net MW	
Heat rate	10.949	MMBtu/net MW	
Baseline Output (2016 - 2018 avg)	529,831.8	MWh	
	22.9%	of full capacity	
Projected Output (2028)	575,835.0	MWhr	
	24.9%	of full capacity	
Projected Heat Input (2028)	6,304,817	MMBtu/yr	
Controlled SO2 Emissions (2016 - 2018 avg)	501	ton/yr	
Uncontrolled SO2 Emissions (2016 - 2018 avg)	2,277.3	ton/yr, calculated	
Proj. Uncontrolled SO2 Emisions (2028)	2,277.3	ton/yr	
Upgraded FGD Removal Efficiency	94	%	
Baseline SO2 Removal (2016 - 2018)	1,776.3	ton/yr	
Controlled SO2 Projected Emissions (2028)	136.6	ton/yr	
Projected SO2 Removal (2028)	2,140.6	ton/yr	
Reagent Stoichiometric Ratio, upgraded system	1.1		
Reagent requirement (2028)	2,722.6	ton/yr	
Reagent cost	200	$/ton	
Waste produced	3.64	ton/ton SO2 removed	
	7,794.4	ton waste/yr	
Waste disposal cost	10	$/ton	
Auxiliary power requirement at full load	5,000.0	kW	
Aux power requirement at 2028 load	1,245.0	kW	
	10,906.0	MWhr/yr	
Auxiliary power cost	50	$/MWhr	
Water requirement at full load	500,000	gal/day	
Water requirement at 2028 load	124,497	gal/day	
	45,442	1000 gal/yr	
Water cost	0.4	$/1000 gal	

Notes:
1 - Chemical Engineering Plant Cost Index (1957 - 1959 = 100)

Cost Estimate - Upgrade FGD System: Retrofit three existing SDA vessels to single atomizer design (2022 $)

Base Equipment Cost (2013 B&W Estimate)	$11,400,000		
DIRECT COSTS			
Base purchased equipment cost (PE)		$15,500,000	
Electrical	15% of PE	$2,330,000	
Instrumentation	5% of PE	$780,000	
Direct equipment installation	90% of PE	$13,950,000	
SUBTOTAL - DIRECT COSTS (DC)		$32,560,000	
INDIRECT COSTS			
Engineering	20% of PE	$3,100,000	
Construction & Field Expensses	10% of PE	$1,550,000	
Contractor fees	10% of PE	$1,550,000	
Startup and Commissioning	1% of PE	$155,000	
Performance testing	1% of PE	$155,000	
Owner's Cost	3% of DC	$977,000	
SUBTOTAL - INDIRECT COSTS		$7,487,000	
CONTINGENCY (15% of Direct and Indirect Costs)		$6,007,000	
TOTAL CAPITAL COST		$46,054,000	2.971225806
ANNUALIZED CAPITAL, OPERATING AND MAINTENANCE COST			
Annualized Capital Cost		$13,521,500	
Variable O&M Cost			
FGD Disposal Cost		$77,900	
Lime Reagent Cost		$544,500	
Auxiliary Power Cost		$545,300	
Water Cost		$18,200	
Total		$1,185,900	
Fixed O&M Cost			
Operating Labor	12 staff @$45/hr, 40 hrs/wk	$1,123,200	
Mantainance Labor	50% of Operating Labor	$561,600	
Maintenance Materials	100% of Maintenance Labor	$561,600	
Total		$2,246,400	
TOTAL ANNUALIZED CAPITAL, OPERATING AND MAINTENANCE COST		$16,953,800	
Overall Cost Effectiveness ($/ton controlled)		$7,920	
Existing FGD system control eff:	78%		
2028 SO2 controlled emissions with existing system:	501.0 ton/yr		
Additional SO2 control achieved with FGD upgrade:	364.4 ton/yr		
Incremental Cost Effectiveness ($/ton controlled)		$46,530	

Waste generation rate, upgraded system:	7,794.4	tons/yr
Waste generation rate, current system:		
- SO2 removal rate	1,776.3	tons/yr
- Stochiometric ratio	1.03	
- Waste generation rate	3.41	ton/ton SO2 removed
	6,056.1	tons/yr
Increase in waste generation rate:	1,738.3	tons/yr

Appendix B.5.j - Response Letter 7

NVEnergy

May 27, 2022

Steven McNeece
Nevada Division of Environmental Protection
901 S. Stewart Street
Suite 4001
Reno, NV 89701

Re: Response to a Seventh Follow-up Request for Additional Information
Regional Haze Four Factor Analyses
NV Energy Valmy (FIN A0375) Generating Station

Mr. McNeece:

Per our discussion during the meeting held May 9, 2022, Sierra Pacific Power Company d/b/a NV Energy (NVE) hereby provides a response detailing Nevada Division of Environmental Protection (NDEP)'s most recent request for additional information regarding the Four Factor Analysis at the North Valmy Generating Station. This response addresses additional information requested by NDEP related to the technical feasibility associated with controls for sulfur dioxide (SO2) emissions from Unit 1.

Please note that this is the response to NDEP's seventh follow-up request for additional information, as NVE also provided responses to NDEP's first request for additional information in a letter dated July 8, 2020, as well as a second request for additional information in a letter dated January 15, 2021, a third request for additional information in a letter dated April 16, 2021, a fourth request for additional information in a letter dated May 7, 2021, two responses to a fifth request for additional information in letters dated August 27, 2021, and October 11, 2021, and a sixth request for additional information in a letter dated April 29, 2022. This letter and attachment address NDEP's most recent questions and should be considered a seventh addendum to the previously submitted Four Factor Analyses dated March 13, 2020.

NVE appreciates the opportunity to work with NDEP in this endeavor. Please feel free to contact Sean Spitzer at (702) 402-5132 should you have any questions.

Sincerely,

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

Valmy Follow-up Response:

Q1: Explain why the existing DSI system on North Valmy Unit 1 should not be considered as an SO_2 emissions reduction system.

NVE Response: As NVE explained in our letter dated April 16, 2021,the DSI system that was installed on North Valmy Unit 1 was designed to meet the emission limit for hydrogen chloride (HCl) under the Mercury and Air Toxics Standards (MATS) rules for utility generation plants. Hydrated lime was selected as the sorbent to use in this system because of its capability to selectively react with HCl rather than with SO_2.
As we explained, the acidic constituents of a boiler's flue gas (including HCl and SO_2) compete for utilization of the sorbent when DSI is employed. We chose hydrated lime as the sorbent for this system because of its preference for HCl over SO_2. Other DSI sorbents (trona or sodium bicarbonate) react more selectively with SO_2 than with HCl. For this reason, DSI systems that are intended to control SO_2 emissions employ either trona or sodium bicarbonate, not hydrated lime.

Furthermore, we explained how the existing DSI system on Unit 1 could not simply be adapted to utilize either trona or sodium bicarbonate to make it an SO_2 emissions control system. The existing system does not have the milling equipment that is a necessary component of a trona or sodium bicarbonate-based DSI system, and the current system contains no provisions to store and inject activated carbon for brown plume control. Consequently, the existing DSI system would need to be completely replaced if the goal were to control SO_2 emissions and meet MATS requirements.

From a theoretical perspective, increasing the SO_2 control efficiency of the existing DSI system on Unit 1 would require an increase in the rate at which hydrated lime is injected. As explained below, however, this is not a technically feasible alternative based on the operating history of the North Valmy DSI system. Accordingly, even though its use indirectly results in a marginal decrease in SO_2 emissions, NVE does not consider the existing DSI system on North Valmy Unit 1 to be an SO_2 emissions reduction system.

Q2: Explain why it would not be appropriate to conduct a four-factor analysis addressing an increase in the hydrated lime injection rate to North Valmy Unit 1.

NVE Response: As noted above, it is theoretically possible to further reduce SO_2 emissions from North Valmy Unit 1 by using higher rates of hydrated lime injection in the existing DSI system. However, based on NVE's actual operating experience with this system, sustained use of high lime injection rates is not a technically feasible alternative and thus not a candidate for a four-factor analysis.

NVE has been operating the DSI system on North Valmy Unit 1 since 2015. The system consists of two parallel sorbent feed trains containing lime unloading equipment, storage silos, and feed systems to deliver lime to the boiler. Lime is transported pneumatically from the storage silos to feed lances located in the boiler flue gas ductwork between the boiler's air heaters and baghouse filter. A total of sixteen feed lances (eight lances per train) are installed. Because hydrated lime is a natural desiccant and absorbs moisture, systems to cool and dehumidify the air used to convey the lime to the boiler are provided on each train. Nonetheless, plugging of the lime delivery and fly ash handling systems with agglomerated sorbent is a substantial and persistent ongoing operational issue for the system. Plugging occurs in the rotary airlock valves that feed lime from the silos to the pneumatic conveyance systems, at elbows and bends within those systems, in the feed lances themselves, and in the fly ash collection hoppers in the baghouse filter. Typically, each delivery train from the silos to the feed lances must be cleaned weekly, and the train being cleaned must be offline during the cleaning process. The parallel feed trains are configured so that one train can be in operation while the other is on standby mode to ensure that a continuous supply of lime can be provided to the boiler if one operating feed train becomes plugged.

The relationship between prevalence of plugging issues and high lime injection rates has been well established from the plant's operating experience. During the first few years of operation of the system, the chlorine content of the coal that was fired in North Valmy Unit 1 was relatively high. At that time, during periods of full load operation both lime injection trains were required to be operated to deliver enough sorbent to meet the MATS HCl emission limit. System plugging problems were a very frequent occurrence during this period of operation. Also, the cementitious nature of western coal fly ash is intensified when fly ash mixes with unreacted lime, so the high lime injection rates used at that time caused substantial plugging problems in the baghouse system's fly ash hoppers. The chlorine content of the coal that is currently being fired is now significantly lower, and Unit 1 now operates almost exclusively at half load due to Idaho Power having withdrawn its 50% participation in the operation of the unit. Consequently, a lower lime injection rate is now utilized to meet the MATS emission limit, and sufficient sorbent can be fed to the boiler using only a single train. Lower lime injection rates, aggressive preventative maintenance, and the use of parallel trains have all contributed to fewer system plugging problems in recent years.

High lime injection rates necessarily mean greater amounts of unreacted lime passing through the system, combining with the fly ash, and being collected in the baghouse. Because all the material collected in the baghouse is disposed of in North Valmy's on-site landfill, ensuring that this material continues to qualify as non-hazardous is an important requirement. Increasing the rate at which lime is injected to the DSI system adds additional risk to compliance with this requirement because it would increase the pH of the fly ash. Generally, solid waste material is considered hazardous by characteristic if it can cause steel corrosion, as measured by a specific EPA test method[1]. Therefore, increased lime usage poses the additional risk of non-compliance with landfill requirements, as corrosive solid waste is not permitted to be deposited into the non-hazardous waste landfill at the North Valmy station.

In summary, a much greater quantity of sorbent than is currently used would need to be injected to control SO_2 emissions from Unit 1 with the existing hydrated lime-based DSI system. As an increased lime injection rate would cause plugging problems and potentially make the collected fly ash hazardous, NVE does not consider this to be a technically feasible alternative. Thus, per Section 7.1 of EPA's 2016 guidance on establishing reasonable progress goals for regional haze improvements[2], we conclude that this alternative is exempt from four factor consideration.

[1] EPA SW-846, Method 1110A

[2] Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/P-16-001, July 2016.

Appendix B.5.k - Response Letter 8

NVEnergy

August 5, 2022

Steven McNeece
Nevada Division of Environmental Protection
Bureau of Air Quality Planning
901 S. Stewart Street, Suite 4001
Carson City, NV 89701

Re: NV Energy Response to an Eighth Follow-up Request for Additional Information Regional Haze Four Factor Analyses Tracy (FIN A0029) and North Valmy (FIN A0375) Generating Station(s)

Dear Mr. McNeece:

Per our discussion during the meeting held August 2, 2022, Sierra Pacific Power Company d/b/a NV Energy (NVE) hereby provides a response detailing Nevada Division of Environmental Protection (NDEP)'s most recent request for additional information received via email regarding the Four Factor Analysis at the Tracy Generating Station and the North Valmy Generating Station. This response addresses additional information requested by NDEP related to the comments received during the draft State Implementation Plan (SIP) public comment period.

Please note that this is the response to NDEP's eighth follow-up request for additional information, as NVE also provided responses to NDEP's first request for additional information in a letter dated July 8, 2020, as well as a second request for additional information in a letter dated January 15, 2021, a third request for additional information in a letter dated April 16, 2021, a fourth request for additional information in a letter dated May 7, 2021, two responses to a fifth request for additional information in letters dated August 27, 2021, and October 11, 2021, a sixth request for additional information in a letter dated April 29, 2022, and a seventh request for additional information in a letter dated May 27, 2022. This letter and attachments address NDEP's most recent questions and should be considered an eighth addendum to the previously submitted Four Factor Analyses dated March 13, 2020.

NVE appreciates the opportunity to work with NDEP in this endeavor. If you have any further questions, please contact Sean Spitzer at (702) 402-5132 or Sean.Spitzer@nvenergy.com.

Sincerely,

Tony D Garcia

Tony D. Garcia, C.E.M.
Manager, Environmental Services
NV Energy

Tracy Follow-up Response:

Q1: The Sierra Club on behalf of themselves and several other conservation organizations provided multiple comments on NDEP's draft SIP evaluation of the appropriateness of additional nitrogen oxide (NOx) emission controls on NVE Unit 7 (Pinon Pine) Generating Unit. In their comments, the Sierra Club asserts that requiring Selective Catalytic Reduction (SCR) on Unit 7 would be more cost-effective than indicated in the draft SIP and they advocate that either SCR should be required on this unit or the unit should be required to be shut down by December, 2028.

NVE Response: To clarify, while Sierra Club uses the name of "Unit 7" to refer to Tracy Piñon Pine in the prompt above, NVE refers to the Tracy Piñon Pine emission unit as "Unit 6" throughout these analyses and will continue to do so for consistency. NDEP's analysis of the potential to install SCR on this unit, similar to the Sierra Club's, concluded that if the unit were to be operated for an extended period of time, that SCR would be a reasonable control to require under the Regional Haze Rule (RHR). However, this unit is planned to be shut down no later than December 31, 2031, and the draft SIP includes an enforceable requirement that it be shut down no later than that date. Given the relatively limited amount of time this unit would remain in operation after controls could be installed, NDEP concluded that it is not reasonable to require SCR to be installed on it.

The remaining useful life of this source is one of the statutory factors that NDEP is required to consider. Although the useful life is used in calculating the cost-effectiveness of a control, it is also a separate statutory factor that NDEP is required to consider. SCR is a very expensive NOx control alternative for this unit, even using Sierra Club's cost estimates of $6.7 million for capital costs and nearly half a million dollars per year for operating costs. NDEP does not believe that it is necessary under the RHR for NVE electrical customers to have to bear this high level of expense to reduce emissions from a source that is planned to be permanently retired in the relatively near future.

Regarding the exact timing of the unit's retirement, the date by which a unit can be shut down is dependent on many factors including the availability of alternative electrical sources to assure reliability of the grid. Also, Unit 6's retirement date will ultimately require the approval by the Public Utilities Commission of Nevada (PUCN) which has responsibility to weigh the best interest of electric utility customers. The SIP proposed retirement date of December 31, 2031 for Unit 6 is the result of many discussions between NDEP and NVE, and NVE's evaluation of what is reasonable given the needs of their electric customers. Although the unit's retirement date in 2031 is outside of this current RHR implementation period, retirement of the unit by this date will be equally effective at meeting the long terms goals of the RHR and is only a short time later than the Sierra Club proposes.

Regarding Sierra Club's specific comments on various elements of the SCR cost-effectiveness analysis, we would like to again emphasize that the cost of controls was only one factor that NDEP considered. Additionally, it should be recognized that both NDEP's and Sierra Club's cost estimates are merely that, "estimates". Most of the points of disagreement with the NDEP's analysis by the Sierra Club are purely subjective and at least one is clearly in error.

The Sierra Club's cost estimate assumes that an SCR system on Tracy Unit 6 could achieve 2 ppm NOx as is commonly achieved by other conventional combustion turbines. However, the Sierra Club appears to have failed to consider that, as explained in NVE's Four Factor Analysis, Unit 6 is equipped with General Electric's gasification compatible combustion system. This system is designed to accommodate a wide spectrum of low heating value fuels, including gasified coal, and as a consequence does not achieve as low an outlet NOx concentration as a unit equipped with conventional natural gas-fired dry low NOx combustors or combustors employing steam injection. Thus, if this unit were to be equipped with SCR it could not achieve the same NOx emission level that could be achieved by a turbine equipped with conventional combustors.

By any cost estimate, the addition of SCR on Tracy Unit 6 would entail a significant expense on both a capital and annual operating cost basis. Given that this unit is required to be retired in the relatively near future, NDEP has properly concluded that it would not be appropriate to require that NVE's electricity customers bear extra expense, and that installing SCR on Unit 6 is not needed to make reasonable progress on meeting the visibility improvement goals of the RHR.

North Valmy Follow-up Response:

Q1: In their comments, Sierra Club appears to take issue with the estimated 22% SO2 removal efficiency of the existing dry sorbent injection (DSI) system on North Valmy Unit 1 that NVE provided to NDEP on April 29, 2022. NDEP requests an explanation as to the basis of the NVE's estimate of the SO2 removal efficiency for the DSI system.

NVE Response**:** Our estimate of the SO_2 removal efficiency of the DSI system on North Valmy Unit 1 is based on the actual SO_2 emissions measured by the unit's SO_2 CEMS, as reported to the EPA's Clean Air Markets Database, and uncontrolled SO_2 emissions estimated using data on coal consumption and sulfur content reported to the Energy Information Administration (EIA). For each of the years 2015 – 2021, an uncontrolled SO_2 emission rate for each month that the unit operated was estimated by multiplying the monthly coal firing rate by the corresponding coal sulfur content and making the appropriate unit conversions; annual uncontrolled SO_2 emission rates for each year were calculated by summing the monthly uncontrolled emission rates. Subsequently, the annual uncontrolled emission rates were compared to the actual SO_2 emission rates that were measured by the CEMS. The following table summarizes the results of these calculations.

Year	Uncontrolled SO_2 (tons)	Controlled SO_2 (tons)	Control Efficiency (%)
2015	5,500	4,470	19%
2016	2,567	1,848	28%
2017	1,587	1,232	22%
2018	2,693	2,357	20%
2019	5,254	4,041	23%
2020	1,707	1,458	15%
2021	2,160	1,646	24%

The average SO_2 control efficiency that we provided to NDEP on April 29, 2022 is simply the average of the annual control efficiencies that were calculated for the 2015 – 2021 period.

We note that the Sierra Club also appears to have used data reported to the EIA and to EPA in the DSI system control efficiency calculations that are summarized in Section 2.2 of their review of the Draft SIP. However, annual controlled SO_2 emission rates calculated from the information presented in this section do not agree with the actual SO_2 emission rates that we reported to the Clean Air Markets Database; annual controlled emission rates calculated using the Sierra Club's information are, on average, approximately 14% higher than the actual emission rates from North Valmy Unit 1. We are unable to explain this discrepancy, but it may be one reason why the DSI control efficiency figures presented by the Sierra Club are lower than the estimate that we provided to you previously.

Q2: In their comments, the Sierra Club also appears to question the SO2 removal efficiency of the dry lime flue gas desulfurization (FGD) system on North Valmy Unit 2 that NVE previously provided to NDEP. NDEP requests an explanation as to how the SO2 removal efficiency for the FGD system was established.

NVE Response**:** NVE monitors SO_2 emissions at both the inlet and outlet of the SO_2 control system on North Valmy Unit 2 as required by the New Source Performance Standards for Electric Utility Steam Generating Units (40 CFR 60 Subpart Da). SO_2 removal efficiency of the system is thus determined by comparing the uncontrolled SO_2 emission rate measured at the inlet to the FGD system with the controlled SO_2 emission rate measured near the flue gas exit to atmosphere near the top of the stack. The ratio of the two values therefore determines the removal efficiency.

Q3: In their comments, the Sierra Club asserts that North Valmy Unit 2 is equipped with a system that allows a portion of the boiler's flue gas to bypass the FGD system and be discharged untreated to the atmosphere. This assertion appears to be based on information reported to the EIA on Form 860. NDEP requests additional information about the FGD bypass system.

NVE Response**:** The FGD system installed on North Valmy Unit 2 was designed to accommodate 100% of the flue gas discharged from the boiler. However, it was also designed with a bypass assembly that includes a damper allowing the capability to divert up to 16% of the flue gas around the FGD system to ensure that the temperature of the gas entering the unit's baghouse would be above the acid gas dew point. It is critical to keep acid from condensing within the baghouse structure, bags, ductwork, and induced draft fans. The temperature of flue gas decreases as it passes through the FGD system and maintaining an appropriate flue gas temperature by bypassing a portion of the flue gas around the FGD system is one way to prevent acid condensation.

In the past, the flue gas bypass system was occasionally employed to maintain the flue gas temperature within acceptable limits. As described above, the SO_2 removal effectiveness of the FGD system on Unit 2 is monitored by separate SO_2 CEMS, one installed at the inlet to the FGD system and another near the top of the stack. Therefore, the reported efficiency of this FGD system, as well as compliance with the unit's SO_2 emission limits, accounts for the portion of the flue gas that bypassed the FGD system. Furthermore, it should be emphasized that the figure reported on EIA Form 860 reflects the bypass capacity of the original FGD system design, not the actual amount of flue gas bypassed each year.

Over time, Unit 2 has experienced excessive plugging problems at the outlet of the FGD system's spray dryer vessels. The problem was exacerbated by lime and ash slurry accumulating on each vessel's bypass ductwork entrance. The problem has since been resolved by upgrading the process control elements on the slurry spray system and permanently sealing the scrubber bypass ductwork entrance on each vessel to eliminate slurry buildup in that location. When these changes became fully implemented in 2020, the pluggage issues were resolved and the capability to bypass flue gas around the FGD system was eliminated.

We note that the EIA Form 860 data for 2021 still reflects the 16% FGD system bypass capability, however this is erroneous and will be corrected in our 2022 EIA report filing to specify that there is no current flue gas bypass capability on Unit 2's FGD system.

Appendix B.6 - Valmy Generating Station, NV Energy

Appendix B.6.a NDEP Reasonable Progress Determination for Valmy Generating Station

Appendix B.6.a - NDEP Reasonable Progress Determination for Valmy Generating Station

North Valmy Generating Station Reasonable Progress Control Determination

Evaluation of existing and potential new control measures at NV Energy's North Valmy Generating Station necessary to achieve reasonable progress for Nevada's second Regional Haze SIP.

Bureau of Air Quality Planning, Nevada Division of Environmental Protection

June 2022

1 Introduction

This document serves as the official reasonable progress determination for the North Valmy Generating Station based on analyses submitted by the owner of the facility. The Long-Term Strategy of Nevada's Regional Haze SIP revision for the second implementation period covering years 2018 through 2028 will rely on the reasonable progress findings of this document. Potential new control measures are evaluated considering the four statutory factors to determine which measures are necessary to achieve reasonable progress. The four statutory factors include: cost of compliance, time necessary for compliance, energy and non-air environmental impacts, and remaining useful life of the source.

This reasonable progress determination references data and analyses provided by NV Energy (NVE) in several documents that can be found in Appendix B.5. Table 1-1 below outlines the documents submitted by NVE that supplement this determination document. In some cases, the Nevada Division of Environmental Protection (NDEP) adjusted information submitted by NVE to ensure the analyses relied on to make reasonable progress determinations agree with Regional Haze Rule regulatory language, Regional Haze Rule Guidance for the second implementation period, and EPA Control Cost Manual. Throughout the document, it can be assumed that referenced data and information rely on the following documents submitted by NVE, unless explicitly indicated that NDEP made adjustments.

Note that, the *NVE Analysis* includes the "Tracy Generating Station Four Factor Analysis" and "Valmy Generating Station Four Factor Analysis." The Tracy and Valmy Four Factor Analyses have separate chapters and appendices residing in the same *NVE Analysis* document. For the purpose of determining reasonable progress for the North Valmy Generating Station, any reference to the *NVE Analysis* pertains to the "North Valmy Generating Station Four Factor Analysis" portion of the document.

Table 1-1: NVE Documents Relied upon for Reasonable Progress Determination

Full Document Title	Shortened Document Title (used in this document)	Date	Appendix Location
Regional Haze Reasonable Further Progress Four Factor Analysis	*NVE Analysis*	March 13, 2020	B.5.b
RE: Response to Request for Additional Information	*Response Letter 1*	July 8, 2020	B.5.c
RE: Response to a Second Follow-up Request for Additional Information	*Response Letter 2*	January 15, 2021	B.5.d
RE: Response to a Third Follow-up Request for Additional Information	*Response Letter 3*	April 16, 2021	B.5.e
RE: Response to a Fourth Follow-up Request for Additional Information	*Response Letter 4*	May 7, 2021	B.5.f
RE: Response to a Fifth Follow-up Request for Additional Information (Valmy specific)	*Response Letter 5.1*	August 27, 2021	B.5.g
RE: Response to a Fifth Follow-up Request for Additional Information (Tracy specific)	*Response Letter 5.2*	October 11, 2021	B.5.h
RE: Response to a Sixth Follow-up Request for Additional Information	*Response Letter 6*	April 29, 2022	B.5.i

RE: Response to a Seventh Follow-up Request for Additional Information	*Response Letter 7*	May 27, 2022	B.5.j
Class I Air Quality Operating Permit	Permit		A.6

2 Facility Characteristics

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.

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 nitrogen oxide (NO_x) emissions through the use of Low NO_x burners and overfired air.

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 (Low NO_x burners and overfire air) to control NO_x emissions, and a lime slurry-based spray dryer to control sulfur dioxide (SO_2) emissions.

3 Emissions Profile

Annual emissions reported by the facility were pulled from the National Emission Inventory (NEI), along with emissions data submitted in the *NVE Analysis* and *Response Letter(s)* that NDEP confirmed by cross checking the data using EPA's Emission Inventory System (EIS) Gateway. These emissions data were used for the source selection process, which Nevada determined using the Q/d method, and for development of baseline emissions to be relied on in the source's Four-Factor Analysis.

3.1 Q/d Emissions Profile

NDEP relied on the Q/d method for source selection by quantifying total facility-wide NO_x, SO_2, and PM_{10} emissions, represented as "Q", reported in the 2014 NEIv2. The Q value was then divided by the distance, in kilometers, between the facility and the nearest Class I area (CIA), represented as "d". The nearest CIA to the North Valmy Generating Station is Jarbidge Wilderness Area at 162 kilometers away. NDEP elected to set a Q/d threshold of 5. As displayed in Table 3-1, using 2014 emissions, the North Valmy Generating Station yields a Q/d value of 75.14, effectively screening the facility into a four-factor analysis requirement for the second round of Regional Haze in Nevada.

Table 3-1: North Valmy Generating Station Q/d Derivation

Facility Name	Nearest CIA	Total Q (tpy)	Distance to CIA (km)	Q/d
North Valmy Generating Station	Jarbidge Wilderness Area	12,173	162	75.14

3.2 Baseline Emissions Profile for Four-Factor Analysis

Although new annual emissions data have become available for North Valmy Generating Station, a 2016-2018 baseline has been used to reflect "normal operations." Reported annual emissions in 2019 and 2020 have since been made available, however, the source has deemed, and NDEP confirmed, that emissions reported in these years would not reflect normal operations.

Emissions reported in 2019 increased due to the rupture of the Enbridge's BC natural gas pipeline in October of 2018, which heavily inflated the cost of natural gas, leading to the increased utilization of North Valmy's coal-fired units. Idaho Power Company (IPC) also increased their usage to deplete coal reserves set aside before IPC ceased operation at Unit 1 on December 31, 2019. Additionally, Unit 2 experienced unplanned outages throughout 2019, requiring a higher utilization of Unit 1. NDEP agrees this year is not representative of normal operations and should not be incorporated into the baseline.

Emissions reported in 2020 are comparable to the 2016-2018 baseline, and further supports that 2019 was not a representative year. This year was not incorporated into the baseline, as the operation of the facility would not be consistent. In 2020, IPC no longer utilized Unit 1, but still withdrew power from Unit 2. To preserve consistency, this reporting year was not incorporated into the baseline.

Table 3-1 compares the reported, facility-wide NO_x, SO_2, and PM_{10} emissions at North Valmy from 2016 through 2020, and shows the spike in emissions in 2019 that are not considered normal operations, along with emissions reported in 2020 that agree with emissions reported in the baseline years. Table 3-2, provided by NVE on page 4 of the *NVE Analysis*, further outlines the reported annual emissions and emission rates for the 2016 through 2018 baseline that were used in determining controls that are necessary to achieve reasonable progress.

Table 3-1: Reported Annual Emissions

	Facility Emissions (tpy)				
Pollutant	**2016**	**2017**	**2018**	**2019**	**2020**
NO_x	1,583	1,219	2,434	2,914	1,603
SO_2	2,277	1,588	3,073	4,558	1,919
PM_{10}	98	51	121	187	75
Total	**3,958**	**2,858**	**5,628**	**7,659**	**3,957**

Table 3-2: Emissions Baseline Used for Four-Factor Analysis

	SO_2	**NO_x**	**PM_{10}**
Baseline Emission Rates for Unit 1			
2016	1,848 ton/yr	797 ton/yr	22.01 ton/yr
2017	1,232 ton/yr	587 ton/yr	16.27 ton/yr

2018	2,357 ton/yr	1,027 ton/yr	27.76 ton/yr
2016-2018 Annual Average	**1,812 ton/yr** **0.760 lb/MMBtu**	**804 ton/yr** **0.337 lb/MMBtu**	**22.01 ton/yr** **0.0092 lb/MMBtu**
Baseline Emission Rates for Unit 2			
2016	431 ton/yr	839 ton/yr	54.84 ton/yr
2017	356 ton/yr	674 ton/yr	20.97 ton/yr
2018	716 ton/yr	1,493 ton/yr	37.19 ton/yr
2016-2018 Annual Average	**501 ton/yr** **0.158 lb/MMBtu**	**1,002 ton/yr** **0.317 lb/MMBtu**	**37.67 ton/yr** **0.0119 lb/MMBtu**

3.3 Reduced Capacity Discussion

In the *NVE Analysis*, baseline emissions were derived from the average emissions recorded between 2016 and 2018. However, in later *Response Letters*, the emissions baseline was manipulated to better represent the projected emissions of the source in 2028. North Valmy is operated by NVE, however, NV Energy shares 50/50 ownership of the plant with Idaho Power. Between both Unit 1 and Unit 2, both NV Energy and Idaho Power own half of each unit's capacity and are not able to surpass the utilization constrained by their half ownership.

In recent years, Idaho Power has committed to stop withdrawing power from their share of North Valmy's Unit 2 by December 31, 2025, and has already ceased withdrawing power from Unit 1 as of December 31, 2019. The baseline used in *Response Letters 1, 2, 3, and 4* was created to forecast what emissions will look like in 2028 by referencing recent historical emissions. Since Idaho Power will no longer be utilizing their ownership and capacity at North Valmy by 2028, NVE developed an emissions baseline for the sake of the 4-factor analysis using 2016-2018 reported emissions subtracting emissions contributed by Idaho Power's portion of power.

Although NDEP recognizes the anticipated reductions in emissions due to Idaho Power committing to stop withdrawing power from their share of the North Valmy units, NDEP must rely on full capacity emissions reported from 2016 through 2018 in establishing an emissions baseline in the absence of a federally enforceable requirement that guarantees that emissions at North Valmy will continue to reflect the reduced capacity scenario for the remainder of the planning period. Since there is no federally enforceable limitation that would guarantee the continued operation at a reduced capacity, **NDEP is relying on full emissions reported for North Valmy during the 2016 through 2018 period to establish an emissions baseline for the purpose of determining what controls are necessary to achieve reasonable progress**.

3.4 Federally Enforceable Closure

NVE has committed to shutting down and permanently ceasing operation at both units at North Valmy by December 31, 2028. This condition is listed in the facility's air quality operating permit (Appendix A.6 of Nevada's Regional Haze SIP for the second implementation period) and is considered necessary to achieve reasonable progress.

The effective closure date was incorporated into the consideration of the "remaining useful life" for each potential new measure considered for the North Valmy units.

4 NO_x Control Determination

4.1 Existing Control Measures

Both North Valmy Unit 1 and Unit 2 are currently configured for multi-stage combustion, including the use of Low NO_x Burners, to control NO_x emissions. NDEP considers the continued use of these controls as necessary to achieve reasonable progress up to the point that both units are shut down and permanently cease operations.

4.2 Potential New Control Measures

The implementation of Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) were considered as potential new control measures to further reduce NO_x emissions at Unit 1 and Unit 2. A control efficiency of 25% is assumed for the implementation of SNCR. It is assumed that SCR can achieve an outlet NOx emission rate of 0.05 pounds per million British thermal units. An interest rate of 6.75% is used in calculating annualized capital costs, as this is the approved rate by the Public Utility Commission of Nevada (PUCN) and represents the “firm-specific nominal interest rate” that is preferred in the EPA Control Cost Manual. NDEP is relying on cost information submitted by NVE for determining whether controls are necessary to achieve reasonable progress. Table 4-1 summarizes the findings of the four-factor analysis conducted to consider potential new NO_x control measures at Unit 1 and Unit 2.

Table 4-1: 4-Factor Summary of Technically Feasible NO_x Control Measures

Control	Unit	Cost of Compliance	Time Necessary for Compliance	Energy and Non-Air Quality Impacts	Remaining Useful Life
SNCR	**Unit 1**	$16,195/ton	35 months	Potential for ammonia slip and back pressure in exhaust flow path	4 years
	Unit 2	$14,100/ton			
SCR	**Unit 1**	$57,583/ton	6 years		
	Unit 2	$54,178/ton			

4.2.1 Identification of Technically Feasible Controls

NDEP is relying on Section 4.3 found on page 4 of the *NVE Analysis (North Valmy Generating Station Four Factor Analysis)* in determining technically feasible controls to consider in reducing NO_x emissions. For Units 1 and 2, it is determined that SCR and SNCR are technically feasible.

4.2.2 Cost of Compliance

NDEP is relying on cost information provided in NVE’s *Response Letter 5.1* in evaluating SNCR as a potential new control measure, and NVE’s *Response Letter 6* in evaluating SCR as a potential new control measure at both Valmy units.

Utilizing the Control Cost Manual spreadsheet in evaluating SNCR as a potential control measure at both Valmy units, NVE calculated a cost-effectiveness value of $16,195/ton and $14,131/ton for Unit 1 and 2, respectively. Cost calculations assume a retrofit factor of 1. A capital recover factor of 0.2936 is used in considering SCR for both units, assuming an interest rate of 6.75% (higher rate confirmed in *Response Letter 1*) and remaining useful life of 4 years (described further in following subsections). As shown in Table 4-3, a total annual cost of implementing SNCR on Unit 1 is estimated at $3.2M and is projected to reduce NO_x emissions by 200 tons per year. For Unit 2, the cost of implementing SNCR is estimated at $3.5M and is projected to reduce NO_x emissions by 250 tons per year.

Table 4-2: Cost of Compliance Summary for SNCR

	Unit 1	Unit 2
Direct Annual Cost	$536,697	$660,378
Indirect Annual Cost	$2,699,155	$2,867,566
Total Annual Cost	$3,235,852	$3,527,944
NO_x Removed Annually	200 tpy	250 tpy
Cost-Effectiveness	**$16,195/ton**	**$14,131/ton**

Utilizing the Control Cost Manual spreadsheet in evaluating SCR as a potential control measure at both Valmy units, NVE calculated a cost-effectiveness value of $57,583/ton and $54,178/ton for Unit 1 and 2, respectively. Cost calculations assume a retrofit factor of 1.3 due to necessary modifications to the auxiliary power system, space constraints, new ductwork, and new steel and reinforcements, as described in *Response Letter 2*. A capital recover factor of 0.2936 is used in considering SCR for both units, assuming an interest rate of 6.75% and remaining useful life of 4 years. As shown in Table 4-3, a total annual cost of implementing SCR on Unit 1 is estimated at $39M and is projected to reduce NO_x emissions by 681 tons per year. For Unit 2, the cost of implementing SCR is estimated at $45.5M and is projected to reduce NO_x emissions by 841 tons per year.

Table 4-3: Cost of Compliance Summary for SCR

	Unit 1	Unit 2
Direct Annual Cost	$1,984,091	$2,324,139
Indirect Annual Cost	$37,206,373	$43,239,347
Total Annual Cost	$39,190,464	$45,563,486
NO_x Removed Annually	681 tpy	841 tpy
Cost-Effectiveness	**$57,583/ton**	**$54,178/ton**

4.2.3 Time Necessary for Compliance

As stated in *Response Letter 5.1*, NVE estimates 35 months would be needed to implement SNCR at both units. In the *NVE Analysis*, NVE estimates at least 6 years would be needed to retrofit both units for SCR.

4.2.4 Energy and Non-Air Quality Environmental Impacts

Both SCR and SNCR have the potential for ammonia slip if too much reagent is emitted unreacted. SCR will increase the parasitic load of the station and cause backpressure in the exhaust flow path.

4.2.5 Remaining Useful Life of the Source

As stated above, NVE has committed to shutting down and permanently ceasing operations at both units at North Valmy by December 31, 2028. This is reflected in annualized capital costs for SNCR and SCR.

Although NVE estimates that a minimum of 35 months would be needed to implement SNCR (approximately 3 years after SIP approval) and a minimum of 6 years to implement SCR, NVE has conservatively estimated that both controls could be implemented by the end of 2024 when calculating the cost of compliance for both controls. Assuming both controls go on-line at the beginning of 2025 and both units permanently close at the end of 2028, a remaining useful life of 4 years is estimated.

4.2.6 Determination for Potential New Measures to Control NOx Emissions

For existing measures, NDEP considers the continued use of multistage combustion, along with the use of Low NO_x Burners, to reduce NO_x emissions as necessary to achieve reasonable progress during the second round of Nevada's Regional Haze SIP for both units.

For potential new measures, NDEP does not consider SNCR or SCR as cost effective, or necessary to achieve reasonable progress for both units.

5 SO_2 Control Determination

5.1 Existing Control Measures

North Valmy Unit 2 is equipped with a lime slurry-based spray dryer to control SO_2 emissions. Unit 1 is not equipped with an active SO_2 control system. Average actual SO_2 emissions for the 2016 and 2018 period were 0.760 lb/MMBtu for Unit 1 and 0.158 lb/MMBtu for Unit 2. NDEP considers the continued use of the existing lime slurry-based dryer as necessary to achieve reasonable progress up to the point that Unit 2 shuts down and permanently ceases operations.

5.2 Potential New Control Measures

An interest rate of 6.75% is used in calculating annualized capital costs, as this is the approved rate by the Public Utility Commission of Nevada (PUCN) and represents the "firm-specific nominal interest rate" that is preferred in the EPA Control Cost Manual. NDEP is relying on cost information submitted by NVE for determining whether controls are necessary to achieve reasonable progress. Table 5-1 summarizes the findings of the four-factor analysis conducted to consider potential new SO_2 control measures at Unit 1 and Unit 2.

Table 5-1: 4-Factor Summary of Technically Feasible SO_2 Control Measures

Control	Unit	Cost of Compliance	Time Necessary for Compliance	Energy and Non-Air Quality Impacts	Remaining Useful Life
Trona DSI	Unit 1	$11,409/ton	34 months	Additional solid waste produced, water losses, increased use of electricity, potential brown plumes.	4 years
Limestone-based FGD	Unit 1	$43,704/ton	6-8 years		4 years
Lime-based FGD	Unit 1	$42,315/ton	6-8 years		4 years
FGD System Upgrade	Unit 2	$46,500/ton	46 months		4 years

5.2.1 Identification of Technically Feasible Controls

NDEP is relying on Section 4.3 found on page 4 of the *NVE Analysis (North Valmy Generating Station Four Factor Analysis)* and *Response Letter 6* to indicate that DSI using milled trona and FGD systems using limestone and lime are technically feasible for Unit 1. Upgrades to spray nozzles at the existing FGD system is the only technically feasible control for Unit 2.

NDEP is relying on *Response Letter 7* in determining that a lime-based DSI system designed to reduce SO_2 emissions at Valmy Unit 1 is technically infeasible due to source specific design limitations.

5.2.2 Cost of Compliance

All potential new SO_2 control measures outlined below assume a capital recovery factor of 0.2936, based on a 4-year equipment life (assuming control goes live beginning of 2025 and plant closes at the end of 2028) and an interest rate of 6.75%.

In evaluating the cost of compliance of replacing the existing DSI system using hydrated lime (designed to control HCl emissions) with a Trona-based Dry Sorbent Injection (Trona DSI) on Valmy Unit 1, NDEP is relying on cost information submitted by NVE in its *Response Letter 6*. As shown in Table 5-2, the total annual cost of replacing the existing DSI system with a Trona-based DSI system is $15.26 million. This system is estimated to reduce annual SO_2 emissions by 1,338 tons, or $11,409 per ton reduced.

In evaluating the cost of compliance of limestone-based flue gas desulfurization on Valmy Unit 1, NDEP is relying on cost information submitted by NVE in its *Response Letter 6*. As shown in Table 5-2, the total annual cost of implementing a limestone-based flue gas desulfurization system is $76.51 million. This system is estimated to reduce annual SO_2 emissions by 1,751 tons, or $43,704 per ton reduced.

In evaluating the cost of compliance of lime-based flue gas desulfurization on Valmy Unit 1, NDEP is relying on cost information submitted by NVE in its *Response Letter 6*. As shown in Table 5-2, the total annual cost of implementing a limestone-based flue gas desulfurization system is $73.77 million. This system is estimated to reduce annual SO_2 emissions by 1,751 tons, or $42,135 per ton reduced.

Table 5-2: Cost of Compliance Summary for Unit 1 SO_2 Controls

Estimated Costs	**Trona Based Dry Sorbent Injection**	**Limestone Based Flue Gas Desulfurization**	**Lime Based Flue Gas Desulfurization**
Capital Cost	$37.4 Million	$247.8 Million	$238.2 Million
Annualized Capital Cost	$10.99 Million	$72.76 Million	$69.95 Million
Annual O&M Cost	$4.27 Million	$3.75 Million	$3.82 Million
Total Annual Cost	$15.26 Million	$76.51 Million	$73.77 Million
Uncontrolled SO_2 Emissions	1,812 tpy	1,812 tpy	1,812 tpy
SO_2 Emission Reduction	1,338 tpy	1,751 tpy	1,751 tpy
Control Cost Effectiveness	**$11,409/ton**	**$43,704/ton**	**$42,135/ton**

NDEP is relying on NVE's cost estimates of upgrading Valmy Unit 2's existing FGD system presented in *Response Letter 6*. The only technically feasible upgrade that could be implemented at Valmy Unit 2's existing FGD system is transitioning the current multi-nozzle spray dryer system to a single nozzle system. As shown in Table 5-3, the total annual cost of upgrading the existing FGD system is estimated at $17 million. An SO_2 removal efficiency of 94% is assume, achieving an annual SO2 reduction of 2,140 tons. Since the existing FGD system already achieves an annual SO_2 reduction of 1,776 tons, upgrading the system would produce an incremental SO_2 reduction of 364 tons per year. This equates to $46,500 per ton reduced.

Table 5-3: Cost of Compliance for Unit 2 SO_2 Controls

Estimated Costs	**FGD System Upgrade**
Capital Cost	$46 Million
Annualized Capital Cost	$13.5 Million
Annual O&M Cost	$3.5 Million
Total Annual Cost	$17 Million
Uncontrolled SO_2 Emissions	2,278 tpy
SO_2 Emission Reduction	364.4 tpy
Control Cost Effectiveness	**$46,500/ton**

5.2.3 Time Necessary for Compliance

As stated in *Response Letter 5.1*, at least 34 months would be needed for DSI installation on Valmy Unit 1. As stated in the *NVE Analysis,* both FGD systems considered for Unit 1 could be implemented withing six to eight years.

For system upgrades to Valmy Unit 2's existing FGD system, NDEP is relying on NVE's estimate provided in *Response Letter 6* that indicates that a minimum of 46 months would be needed to implement the upgrades.

For the purpose of calculating annualized costs, NVE assumes a 4-year life, which is more conservative than the various compliance schedules for each control.

5.2.4 Energy and Non-Air Quality Environmental Impacts

All potential SO_2 controls would produce solid waste that would trigger EPA's CCR disposal rules. NVE estimates water losses over 61,000 gallons per day via evaporative losses that will occur when the hot boiler flue gas contacts the FGD reagent slurry. Electricity use would also increase in order to operate the system. All of these factors have been accounted for in the cost analysis. DSI systems have the potential to emit a yellow/brownish plume due to excess NO_x. Activated carbon injection is included in the cost analysis to mitigate this.

5.2.5 Remaining Useful Life of the Source

As stated above, NVE has committed to shutting down and permanently ceasing operations at both units at North Valmy by December 31, 2028. All potential SO_2 control measures evaluated assume a remaining useful life of 4 years.

5.2.6 Determination for Potential New Measures to Control SO_2 Emissions

NDEP does not consider any new SO_2 control measures at either Valmy units as necessary to achieve reasonable progress.

6 PM_{10} Control Determination

6.1 Existing Control Measures

Both units at North Valmy Generating Station use baghouses to control particulate emissions, and air atomized ignitors to control particulates during startup and for flame stabilization. Additional potential measures to control PM_{10} emissions were not evaluated for the North Valmy units, as the baghouses represent existing effective controls.

NDEP considers the continued use of PM_{10} control measures at both North Valmy units as necessary to make reasonable progress up to the point that both units are shut down and permanently cease operations.

7 Control Measures Necessary to Make Reasonable Progress

As stated above, NDEP considers a federally enforceable closure date for both North Valmy units of December 31, 2028, as necessary to make reasonable progress. Prior to closure, NDEP is also relying on the continued use of existing controls at Unit 1 (baghouse to control PM_{10} emissions and Low NO_x burners and over fired air to control NO_x emissions) and Unit 2 (baghouse to control PM_{10} emissions, Low NO_x burners and over fired air to control NO_x emissions, and spray dryer using a lime slurry to control SO_2 emissions) to make reasonable progress.

NDEP is submitting the following controls, emission limits, and associated requirements, for approval into the SIP as measures necessary to make reasonable progress during second implementation period of Nevada's Regional Haze SIP. These emission limits and associated requirements, listed in the source's air quality operating permit, are incorporated into the SIP by reference. The North Valmy Generating Station's permit, Permit No. AP4911-0457.03, can be found in Appendix A.6 of Nevada's second Regional Haze SIP.

7.1 Unit 1 Limits and Associated Requirements

For Unit 1 (System 01 – Unit #1 Boiler).

7.1.1 Emission Limits found in Section VI.A of Permit No. AP4911-0457.03

1. NAC 445B.3405 (NAC 445B.316) *<u>Part 70 Program</u>*

<u>Air Pollution Control Equipment</u>

a. Control system consisting of:

(1) Baghouse to control particulate matter emissions.

(2) Air atomized ignitors to control particulate matter and opacity during startup and for flame stabilization.

(3) Multi-stage combustion to control nitrogen oxides emissions through the use of Low NO_X Burners and Over Fired Air.

2. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

Emission Limits

On and after the date of startup of **S2.001**, ***Permittee*** will not discharge or cause the discharge into the atmosphere from the exhaust stack of **S2.001** the following pollutants in excess of the following specified limits:

b. 40 CFR Part 60.42(a)(1) *Federal Enforceable New Source Performance Standard Requirement* – The discharge of **PM** (total particulate matter) to the atmosphere will not exceed **0.10** pound per million Btu.

e 40 CFR Part 60.44(a)(3) *Federal Enforceable New Source Performance Standard Requirement* – The discharge of **NO_X** (nitrogen oxides) to the atmosphere will not exceed **0.70** pound per million Btu, based on a 3-hour rolling average.

7.1.2 Monitoring, Recordkeeping, and Reporting Requirements

NDEP is relying on the monitoring, recordkeeping, and reporting requirements listed in Section V and Section VI.A.4 of Permit No. AP4911-0457.03.

7.1.3 Compliance Deadline

NDEP is incorporating the following permit condition by reference, found in Section VII of Permit No. AP4911-0457.03, for approval in the SIP to establish a closure date of December 31, 2028, at Unit 1 to make reasonable progress.

Section VIII. Schedules of Compliance

A. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

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 01 (S2.001)** and **System 02 (S2.002)** no later than December 31, 2028.

7.2 Unit 2 Limits and Associated Requirements

For Unit 2 (System 02 – Unit #2 Boiler).

7.2.1 Emission Limits found in Section VI.B of Permit No. AP4911-0457.03

1. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

Air Pollution Control Equipment

a. Control system consisting of:

(1) Baghouse to control particulate matter emissions.

(2) Spray dryer using a lime slurry with a rated **70%** minimum sulfur dioxide removal efficiency.

(3) Air atomized ignitors to control particulates and opacity during startup and for flame stabilization.

(4) Multi-stage combustion to control nitrogen oxides emissions through the use of Low NO_x Burners and Over Fired Air.

2. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

Emission Limits

On and after the date of startup of **S2.002**, ***Permittee*** will not discharge or cause the discharge into the atmosphere from the exhaust stack of **S2.002,** the following pollutants in excess of the following specified limits:

b. 40 CFR Part 60.42Da(a) *Federally Enforceable New Source Performance Standard Requirement* – On and after the date on which the performance test required to be conducted under 40 CFR Part 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain **particulate matter** in excess of:

(1) 13 ng/J (**0.03 lb/million Btu**) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel;

(3) and 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

e. 40 CFR Part 60.44Da(a) *Federally Enforceable New Source Performance Standard Requirement* – On and after the date on which the initial performance test required to be conducted under 40 CFR Part 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under 40 CFR Part 60.44Da(a), any gases which contain **nitrogen oxides** (expressed as NO_2) in excess of the following emission limits, based on a 30-day rolling average, except as provided under 40 CFR Part 60.48Da(j)(1):

(1) 210 ng/J (**0.50 lb/million Btu**) heat input derived from the combustion of Sub-bituminous coal;

(2) 260 ng/J (**0.60 lb/million Btu**) heat input derived from the combustion of Bituminous coal;

(3) 65 percent reduction of potential combustion concentration when combusting solid fuel.

i. 40 CFR Part 60.43Da(a) and (g) *Federally Enforceable New Source Performance Standard Requirement* – On and after the date on which the initial performance test required to be conducted under 40 CFR Part 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs 40 CFR Part 60.43Da(c), (d), (f) or (h), any gases that contain **sulfur dioxide** in excess of:

(1) 520 ng/J (**1.20 lb/million Btu**) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (**0.60 lb/million Btu**) heat input.

Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

7.1.2 Monitoring, Recordkeeping, and Reporting Requirements

NDEP is relying on the monitoring, recordkeeping, and reporting requirements listed in Section V and Section VI.B.4 of Permit No. AP4911-0457.03.

7.1.3 Compliance Deadline

NDEP is incorporating the following permit condition by reference, found in Section VII of Permit No. AP4911-0457.03, for approval in the SIP to establish a closure date of December 31, 2028, at Unit 2 to make reasonable progress.

Section VIII. Schedules of Compliance

A. NAC 445B.3405 (NAC 445B.316) *Part 70 Program*

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 01 (S2.001)** and **System 02 (S2.002)** no later than December 31, 2028.