Regional Haze Four-Factor Analysis and Visibility Impacts Review

Prepared for
Northwest Pipeline LLC – Baker

June 2020

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1 Executive Summary

Northwest Pipeline, LLC Baker Compressor Station (NWP Baker) has demonstrated in the visibility impact review in Section 5 of this document, that the NWP Baker should not be required to conduct a four-factor analysis.

Upon request from the Oregon Department of Environmental Quality (ODEQ), NWP Baker conducted a four-factor analysis on the facility's natural-gas-fired reciprocating internal combustion engines (RICE) to reduce NO_X emissions. As part of this analysis, the facility evaluated the cost effectiveness of technically feasible control technologies (see Appendix A-1 and A-2) for the existing engines included in Table 1-1 and does not consider the control costs to be economically feasible.

NWP Baker also conducted a review of the screening conducted by ODEQ and completed an evaluation of the meteorological conditions in northeastern Oregon to determine if there is sufficient cause to conclude NO_X emission reductions at NWP Baker would be beneficial to visibility at Eagle Cap Wilderness Area and Strawberry Mountain Wilderness.

The report evaluates potential NO_X control technologies and feasibility considerations, the site-specific four-factor analysis, and a visibility impacts review. NWP Baker has concluded that new emission controls are not warranted because the cost of compliance of technically feasible retrofit emission control technologies is not reasonable and visibility benefits on the haziest days from facility emission reductions are not likely to occur.

Table 1-1 NWP Baker Sources Included in Four-Factor Analysis

Engine Type	EU ID (Device ID)	Fuel Type	Year of first operation	Engine Rating (Horsepower)
Copper Bessemer GMWA-6	EU1 (C1)	Pipeline Grade Natural Gas	1956	1,500
Copper Bessemer GMWA-6	EU1 (C2)	Pipeline Grade Natural Gas	1956	1,500
Copper Bessemer GMWA-6	EU1 (C3)	Pipeline Grade Natural Gas	1956	1,500
Copper Bessemer GMVH-8	EU2 (C4)	Pipeline Grade Natural Gas	1981	1,800

2 Introduction

The regulatory background and facility information are summarized below.

2.1 Regulatory Background

The 1977 amendments to the Federal Clean Air Act included a national goal such that "… *the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution.*"[1] To address the problem of regional haze and to meet the national goal of reducing man-made visibility impairment in all Class I areas, the U.S. Environmental Protection Agency (EPA) adopted "Phase II" visibility rules in 1999—also known as the Regional Haze Rule (RHR). The primary purpose of the rule is to improve visibility by 2064 in Class I areas (e.g., national parks and wilderness areas) across the country by developing regional haze state implementation plans (SIPs) that focus on improving visibility on the 20% most impaired days and protecting the clearest days (20% clearest days).

The Oregon Department of Environmental Quality (ODEQ) is required to develop and implement a SIP to reduce the pollution that causes haze at national parks and wilderness areas (40 CFR 51.308). ODEQ submitted its first regional haze SIP in 2010 and the SIP for the second planning period, 2018-2028, is required to be submitted in 2021.

As part of the planning process for the updated SIP development, ODEQ evaluated emissions of haze causing pollutants from major stationary sources. As a result of this evaluation, the ODEQ issued a letter to NWP on December 23, 2019, which identified this facility as a significant source of regional haze precursor emissions based on past actual emissions and the potential-to-emit.[2] The letter requested that NWP submit a four-factor analysis for the facility and provided an option for demonstrating that certain emission units are too small to control. The ODEQ extended the June 1, 2020 due date from the December 23, 2019 letter to June 15, 2020, in a letter dated April 21, 2020.

The four-factor analysis is outlined in 40 CFR 51.308(f)(2)(i) which requires the state to consider the following factors:

1. The costs of compliance
2. The time necessary for compliance
3. The energy and non-air quality environmental impacts of compliance
4. The remaining useful life of any potentially affected major or minor stationary source or group of sources

[1] 42 U.S. Code §7491(a)(1)

[2] Mirzakhalili, Ali (IDEQ), Letter to Robert Harmon (NWP), December 23, 2019.

This analysis also considers guidance issued by the EPA on August 19, 2019 ("the 2019 Guidance")[3].

2.2 Facility Information

NWP Baker is a natural gas compression station and is located at 18193 Chandler Lane, Baker City, Oregon. The facility has four natural gas-fired lean-burn RICE as summarized in Table 2-1.

Table 2-1 NWP Baker Sources Included in Four-Factor Analysis

Engine Type	EU ID (Device ID)	Fuel Type	Year of first operation	Engine Rating (Horsepower)
Copper Bessemer GMWA-6	EU1 (C1)	Pipeline Grade Natural Gas	1956	1,500
Copper Bessemer GMWA-6	EU1 (C2)	Pipeline Grade Natural Gas	1956	1,500
Copper Bessemer GMWA-6	EU1 (C3)	Pipeline Grade Natural Gas	1956	1,500
Copper Bessemer GMVH-8	EU2 (C4)	Pipeline Grade Natural Gas	1981	1,800

The facility operates under a Tier I Operating Permit as issued by the ODEQ:

- Permit Number: 01-0038-TV-01
- Application Number: 28144
- Federal Facility ID: 7219111
- Date Issued: January 12, 2017
- Date Expires: January 04, 2022

The ODEQ Facility Description for the permit describes the facility as follows:

> *The Baker Compressor Station is located about 7.5 miles northwest of Baker City, Oregon. The Baker Compressor Station contains four natural gas-fired reciprocating engines to drive pipeline compressor units. In addition, the facility includes a small natural-gas-fired boiler which provides building heat, a natural gas-fired emergency generator/engine set, and various condensate, lubricating oil, glycol and waste oil storage tanks. High pressure natural gas piping is located both above and below ground.*

[3] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019

The operation of the facility varies to meet the demand of the pipeline system with the highest fuel usage typically in the winter months (see Figure 5-2). As described in the facility permit description, the facility also operates combustion sources that include a small natural-gas-fired boiler, which provides building heat and a natural gas-fired emergency generator/engine set. These sources were determined to be de minimis[4] and not analyzed further by this four-factor analysis. This determination reflects that the maximum capacity and actual emissions emitted are significantly lower than EU1 and 2 and not likely to significantly contribute to regional haze or have an observable visibility benefit by additional controls.

2.2.1 Small Emission Units (Not Further Considered in this Analysis)

The emission units which were considered too small to be included in the four-factor analysis are summarized in Table 2-2. The largest source not to be included in the four-factor analysis is the Sellers Natural Gas Boiler (EU4), which results in less than 1% of actual facility NO_X emissions averaged from 2014 to 2019 and is used for building heat

Table 2-2 NWP Baker Sources Too Small to be Included in Four-Factor Analysis

Emission Source	Sellars Boiler (EU4)	Waukesha Emergency Generator Engine (AUX-1)	Storage tanks and piping
Purpose	Building heater	Emergency power generation	Storage and fluid transfer
Maximum Capacity or Rating	5.30 MMBtu/hour	201 horsepower	Not applicable – this is not a combustion source.
Fuel Type or Throughput	Pipeline Grade Natural Gas	Pipeline Grade Natural Gas	Various condensate, lubricating oil, glycol and waste oil
Average Actual NO_X Emissions (TPY)[5]	0.38	0.04	Not a combustion source – not likely to have NO_X emissions.
NO_X PTE (TPY)	2.3	Aggregate Insignificant Activity	Not applicable
% of Facility Actual Total NO_X Emissions per Year	0.3%	0.03%	Not applicable
Too Small to control or to be analyzed in further detail	Yes	Yes	Yes

[4] Table 2-2 NWP Baker Sources Too Small to be Included in Four-Factor Analysis
[5] The actual average NO_X emissions were calculated using the emissions from 2014 through 2019 for EU4, and for AUX-1, the average was calculated using available emissions for 2016 through 2019.

2.2.2 Compressor Engines

This analysis focuses on the three Cooper GMWA-6s (EU1) and one Cooper GMVH-8 (EU2) engines. The operation of these sources varies to meet the demand of the pipeline system with the highest fuel usage observed seasonally, in the summer and winter months (see Figure 5-2 NWP Engine Fuel Usage by Month, 2014-2019).

2.2.3 Compressor Engines – Effective Controls for SO_2 and PM

The three Cooper GMWA-6s (EU1) and one Cooper GMVH-8 (EU2) engines only combust pipeline natural gas. The 2019 Guidance states that fuel combustion units that only combust pipeline natural gas, per enforceable requirements, are "effectively controlled" for SO_2 and PM.[6] EPA referenced that "SO_2 controls or more stringent limits on the sulfur content of the natural gas would very likely not be determined to be necessary to make reasonable progress." The guidance further states that states can exclude "effectively controlled" from needing to complete a "four-factor analysis." Thus, these sources are considered effectively controlled for SO2 and PM. Therefore, this four-factor analysis will evaluate in detail only NO_X control technologies for EU1 and EU2 as outlined in 40 CFR 51.308(f)(2) and to be included in ODEQ's SIP submittal.

3 Potential Control Technologies for the Four-Factor Analysis

The 2019 Guidance states that the "first step in characterizing control measures for a source is the identification of technically feasible control measures...."[7] The 2019 Guidance further says that a "state must reasonably pick and justify the measures that it will consider, recognizing that there is no statutory or regulatory requirement to consider all technically feasible measures or any particular measures."[8] Potential control technologies and their feasibility are discussed in Section 3.1 and technologies that are carried forward to the four-factor analysis are summarized in Section 3.2.

3.1 Potentially Available Control Technologies

Potentially available control technologies to reduce NO_X from the NWP Baker engines are summarized below.

3.1.1 Air/Fuel Ratio Controllers

NO_X formation decreases as the combustion mixture becomes more fuel-lean. Air/fuel ratio controllers modify the amount of fuel and air injected to ensure an optimal mixture, which minimizes NO_X emissions.

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[6] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 24.
[7] Ibid, Page 28.
[8] Ibid, Page 29.

NWP Baker already has this control technology installed on all four engines. This technology will not be discussed further in this analysis.

3.1.2 Ignition Timing Delay

Delaying the ignition timing ensures the fuel ignites entirely during expansion rather than initially during compression and mostly during expansion. This results in a lower combustion temperature and reduced thermal NO_X formation.

NWP Baker already has this control technology installed on all four engines. This technology will not be discussed further in this analysis.

3.1.3 Low Emission Combustion Retrofit

A low emission combustion (LEC) retrofit enhances the effectiveness of air/fuel ratio controls by allowing an even leaner fuel mixture to enter the combustion chamber. This can be accomplished by pre-combustion chambers or high-pressure fuel injection, but can vary depending upon the engine type and equipment supplier. However, an LEC retrofit normally requires additional engine modifications and additional supporting equipment modifications for high-pressure fuel injection to accommodate the retrofit. Leaner fuel mixtures require additional air, which is accommodated by modifications to turbochargers. In addition, the lean fuel mixture may require additional instrumentation to monitor each cylinder to avoid misfire and engine failure. Finally, LEC retrofits typically require intercooler upgrades as well.

LEC retrofit is technically feasible for all engines. EU2 already has pre-combustion chambers installed, which is considered a partial LEC retrofit.

3.1.4 Selective Non-Catalytic Reduction (SNCR)

SNCR reduces NO_X emissions with ammonia or urea injection into a heater or boiler exhaust. A temperature range of 1,600°F to 2,100°F is required.[9] At these temperatures, the ammonia and NO_X react to form N_2 and H_2O. If urea is used, it will break down into ammonia after it is injected and will then react with NO_X.

The GMWA-6 engines and the GMVH-8 are typically operated between 540°F and 645°F respectively. SNCR requires a minimum reaction temperature of 1,600°F. If the exhaust was heated to the minimum temperature, more NO_X would be generated. Therefore, SNCR is not technically feasible for the NWP engines and is eliminated from further consideration.

[9] EPA, *Air Pollution Control Technology Fact Sheet for* SNCR (https://www3.epa.gov/ttncatc1/dir1/fsncr.pdf), Page 1.

3.1.5 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) reduces NO_X emissions with ammonia or urea injection in the presence of a catalyst. The catalyst enables the de-NO_X reactions to proceed at a lower temperature than SNCR. Most SCR catalysts must operate at 500°F to 800°F in order to work.

SCR is most commonly applied to large utility boilers and turbines with limited gas transmission applications. The Interstate Natural Gas Association of America (INGAA) noted in 2014:[10]

> *"To date, SCR application to U.S. gas transmission sources has been very limited, and SCR has not been applied to an existing integral engine. Technical concerns about the SCR performance for gas transmission engines include exhaust temperature requirements, reagent control (and sophistication of current systems), and treatment of potential variations in the reciprocating engine exhaust NO/NO_2 ratio….*
>
> *…Recently, some new 4-stroke cycle lean burn engines have been sited with SCR, but retrofit application to lean burn prime movers has not occurred…. Engines that have variable power loads require more sophisticated controls to inject the proper amount of reagent, and it is not evident that robust control schemes have been developed for transmission applications…."*

Therefore, SCR has not been sufficiently demonstrated in practices on engines like the four engines at NWP Baker. In addition, the engines at the facility operate with varying loads and intermittently throughout the year as needed to maintain pipeline operation and demand. This would require sophisticated controls to ensure proper reagent addition to avoid ammonia slip, which can lead to potential visibility impacts if not well controlled. Also, load swings can cause temperature fluctuations hindering the performance and efficiency of the SCR system. Therefore, SCR is not considered to be technically feasible for the NWP Baker engines and is eliminated from further consideration.

3.1.6 Non-Selective Catalytic Reduction (NSCR)

Non-Selective catalytic reduction (NSCR) is a NO_X control method which utilizes a three-way catalyst to simultaneously control NO_X, CO, and VOC emissions. CO and unburned hydrocarbons are used at the reducing agents for converting NO_X to N_2 and H_2O. The catalyst typically utilizes noble metals such as platinum, palladium, or rhodium. NSCR catalysts require low oxygen concentrations (< 0.5% O_2) and an operating temperature range of 700°F to 1,200°F. Due to these restrictions, NSCR is typically used for controlling emissions from rich-burn internal combustion engines.

NSCR is designed for rich-burn engines, not lean-burn. NSCR catalysts require low oxygen concentrations (< 0.5% O_2), which is far below the range that the NWP engines typically operate of greater than 15% O_2.

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[10] The INGAA Foundation, Inc., *Availability and Limitations of NO_X Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry (https://www.ingaa.org/File.aspx?id=22780)*, July 2014, Page 9.

Therefore, NSCR is not technically feasible for the NWP Baker engines and is eliminated from further consideration.

3.1.7 Electric Compressors

Replacing the engines with electric compressors was determined to be to not within the scope of the four-factor analysis. Per the EPA, examples of emission-control measures states may consider include "fuel mix with inherently lower SO_2, NO_X, and/or PM emissions. States may also determine that it is unreasonable to consider some fuel-use changes because they would be too fundamental to the operation and design of a source."[11] The replacement of a gas-driven compressor to an electric compressor is an unreasonable fuel-use change since it requires a fundamental change to the source.

3.2 Technologies Proceeding to Four-Factor Analysis

The technical feasibility of potential control technologies is summarized in Table 3-1.

Table 3-1 Technical Feasibility of NO_X Emission Control Technologies for NWP Baker Engines

Section	Technology	Technically Feasible?	Proceed to Four-Factor Analysis?
3.1.1	Air/Fuel Ratio Controllers	Yes (already installed)	No
3.1.2	Ignition Timing Delay	Yes (already Installed)	No
3.1.3	LEC Retrofit	Yes	Yes
3.1.4	SNCR	No	No
3.1.5	SCR	No	No
3.1.6	NSCR	No	No
3.1.7	Electric Compressors	No	No

[11] USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, 08/20/2019, Page 30.

4 Four-Factor Analysis

4.1 Cost of Compliance

Economic impacts were analyzed using vendor cost estimates along with the procedures found in the EPA Air Pollution Control Cost Manual (CCM) as applicable. The source of the control equipment cost data are noted in each of the control cost analysis worksheets in Appendix A-1 and A-2.

Cost effectiveness is evaluated on a dollar-per-ton ($/ton) basis using the annual operating cost ($/year) divided by the annual emission reduction achieved by the control device (ton/yr).

4.1.1 Uncontrolled (Baseline) Emission Rates

The 2019 Guidance states that the "projected 2028 (or the current) scenario can be a reasonable and convenient choice for use as the baseline control scenario for measuring the incremental effects of potential reasonable progress control measures on emissions, costs, visibility, and other factors."[12] Thus, NWP estimated the 2028 emissions as the "uncontrolled" or "baseline" emission rates. NWP Baker operates the engines on an as-needed basis to meet the demand of the pipeline system rather than a fixed schedule, which results in the actual emissions being much lower than the PTE and, thus, the actual emission rates will be a better indicator of 2028 emission rates. The actual annual emissions data from 2014 through 2019 are presented in Table 4-1.

Table 4-1 NWP – Baker Annual Baseline NO_X Emissions (tons per year)

Year	Cooper Bessemer GMWA-6 #1	Cooper Bessemer GMWA-6 #2	Cooper Bessemer GMWA-6 #3	Cooper Bessemer GMVH-8	Total
2014	20.99	10.24	12.94	16.75	60.92
2015	45.61	35.60	21.48	26.78	129.47
2016	16.07	21.03	18.55	11.95	67.59
2017	31.21	44.81	50.80	30.12	156.94
2018	66.82	43.70	65.53	51.74	227.80
2019	31.00	15.88	9.69	25.97	82.53
5-year Average	**35.28**	**28.54**	**29.83**	**27.22**	**120.87**

NWP Baker expects future engine operation to be similar to current operations. However, engine operation is highly dependent on product demand, weather patterns, pipeline maintenance, and upstream/downstream pipeline impacts. These factors create a considerable amount of uncertainly as to the expected annual operating hours of each engine for a specific year, but multi-year average operating

[12] Ibid, Page 29.

rates are expected to be steady. Therefore, NWP has estimated the 2028 uncontrolled (baseline) emission rate as the average emission rate for each engine for the five-year period from 2014 to 2019. This assumption of flat growth (i.e., a growth factor of one) is consistent with the 2014-2028 projections for gas transmission sources in Baker County, Oregon, used as part of the WRAP regional haze modeling analyses.

In addition, typical operation is to operate EU2 first and then add EU1 (C1, C2, and C3), if needed, one at a time to meet pipeline demand. For EU1 (C1, C2, and C3), the actual engine placed into service will vary. Therefore, NWP used the average of the emission rates and operating hours combined for EU1 (C1, C2, and C3) to conduct a single cost evaluation.

4.1.2 Cost Results

The details of the control cost evaluation are included in Appendix A-1 and A-2. The findings of the economic analysis are summarized in Table 4-2. Note, the LEC retrofit does not include balance of plant costs needed to increase the fuel supply pressure to meet the design requirements, which could be significant. Therefore, the cost effectiveness calculations presented in Table 4-1 may be conservatively low.

Table 4-2 Cost Effectiveness of NO_X Emission Control Technologies for the NWP Engines

Emission Source	Technology	Cost Effectiveness ($/ton NO_X Removed)	Cost Effective?
GMWA-6 Engines Combined	LEC Retrofit	$25,850	No
GMVH-8 Engine	LEC Retrofit	$24,243	No

Based on the information provided in Table 4-1 and in consideration of four-factor analyses conducted in other states, LEC Retrofit was not considered to be cost effective for the engines at NWP Baker.

4.2 Time Necessary for Compliance

NWP determined that no controls are technically or economically feasible. Therefore, this section does not apply.

4.3 Energy and Non-Air Quality Impacts of Compliance

NWP determined that no controls are technically or economically feasible. Therefore, this section does not apply.

4.4 Remaining Useful Life of Sources

NWP has no immediate plans to retire any of the existing engines. The expected life of each engine is at least 20 years, which was be used as the basis for the equipment life in the control costs from Section 4.1.2. EU1 (C1, C2, and C3) were installed in 1956 and EU2 was installed in 1981.

5 Visibility Impacts Review

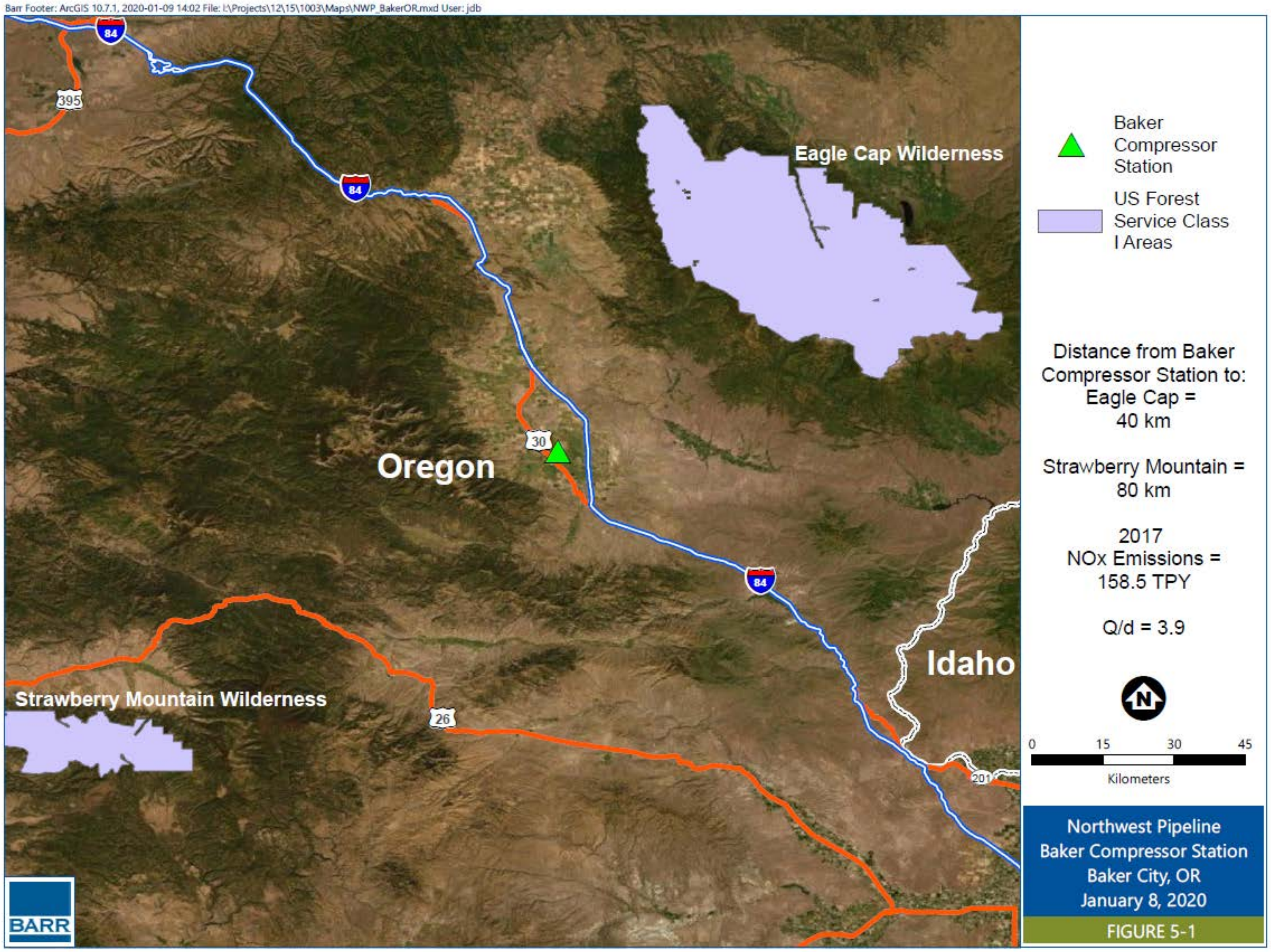
Although a visibility impacts analysis is not specifically required to be included with the four-factor analysis, it is part of the source selection to conduct a four-factor analysis. Further, Section II, B, Step 4(g) of the regional haze guidance[13] provides the following:

> *"While visibility impacts and/or potential benefits may be considered in the source selection step in order to prioritize the examination of certain sources for further analysis of emission control measures, visibility benefits may again be considered in that control analysis to inform the determination of whether it is reasonable to require a certain measure."*

Therefore, NWP conducted a review of the Q/d screening conducted by ODEQ and an evaluation of the meteorological conditions in northeastern Oregon to determine if there is sufficient cause to conclude NO_X emission reductions at NWP Baker would be beneficial to visibility at Eagle Cap Wilderness Area. Figure 5-1 presents a map showing NWP Baker in relation to the Eagle Cap Wilderness Area.

[13] *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (U.S. EPA, August 2019)

Figure 5-1 **Northwest Pipeline Baker Engines**



5.1 Estimating Visibility Impacts for Source Selection

The 2019 Guidance offers recommendation for applying visibility impact estimates when selecting which sources should conduct a four-factor analysis. The guidance says that the simplest method for considering the visibility impact is by using a "source's annual emissions in tons divided by distance in kilometers between the source and the nearest Class I area (often referred to as Q/d) as a surrogate for source visibility impacts, along with a reasonably selected threshold for this metric."[14] Pursuant to the January 9, 2020 conference call conducted by ODEQ to discuss the request for the analyses with facilities/companies, ODEQ stated that Q/d greater than five (>5) was used as the screening threshold for elimination from the four-factor analysis.

Initially, the average annual emissions were compared to the NO_X emissions used in the screening by ODEQ (158.5 tons/year). As illustrated in Figure 5-1 and based on the closest distance to the Eagle Cap Wilderness Area referenced by ODEQ for evaluation of possible impacts (40 km), the screening evaluation concludes the emission / distance (Q/d) is:

ODEQ Q/d = 158.5 tons/year / 40 km = 3.96

NWP Q/d = 120.9 tons/year / 40 km = 3.02

Since both values are less than the screening threshold selected by ODEQ, it is logical that no further analysis is needed. However, ODEQ went beyond the EPA-recommended use of actual emissions and included the potential emissions in the Q/d calculation (542 tons/year) which resulted in a Q/d above the ODEQ threshold (5).

It is important to note that both of the calculated Q/d's are well below values that have been used in this type of screening analyses by state agencies and the federal land managers over the years. A Q/d of 10 is most commonly used to screen out sources from downwind Class I visibility analyses. .

Based on the use of the actual emissions as detailed in the EPA guidance and the ODEQ-selected Q/d of 5, it would be appropriate to eliminate Baker from further consideration based on the initial Q/d screening technique.

5.2 Emission Inventory Seasonal Review

The visibility review considered the 2014-2019 annual emission inventory data for three GMWA-6 (Units 1-3) and the GMVH-8 (Unit 4) engines. The results suggest that the emissions are very small compared to other sources who have been required to conduct Best Available Retrofit Technology (BART) evaluations under the original regional haze SIPs and as part of this second-round evaluation. The emissions data is shown in Table 4-1. In other words, it is rare to consider a source that has emissions of 100-200 tons per year as part of this type of control evaluation as the cost of any control would be extremely high compared to the reductions achieved (as shown here). Further, the impact of these emissions are a

[14] Ibid, Page 13.

downwind Class I area would also be very small compared to other sources in the inventory (e.g., mobile source NO_X emissions)

In addition, the seasonal nature of these emissions was also evaluated. Figure 5-2 contains the fuel use by months for the NWP engines, Units 1-5. Barr used this plot to provide an illustration of the seasonal emission patterns as the emissions are based on fuel consumption by the engines. The figure illustrates a late fall / winter peak for each year along with limited fuel usage during the summer. In later years, there has been additional variability in the late spring / early summer months.

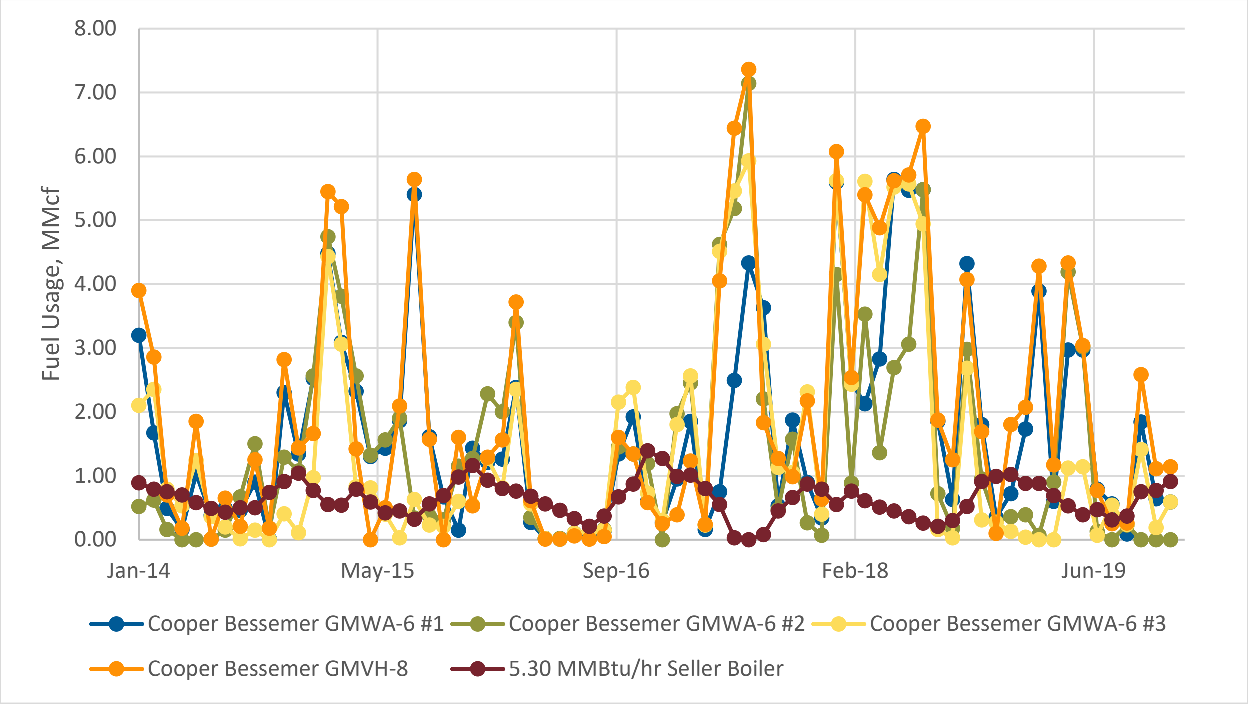


Figure 5-2 NWP Engine Fuel Usage by Month, 2014-2019

5.3 Review of Visibility Impacts at Eagle Cap and Strawberry Mountain

5.3.1 Pollutant analysis

Recent (2014-2018) monitoring data at Starkey Experimental Forest (the nearest and most representative visibility monitoring site to Eagle Cap and Strawberry Mountain Wilderness Areas[15]) indicates that visibility impacts are largely driven by organic mass and ammonium sulfate on the cleanest days and organic mass on the haziest days. Interagency Monitoring of Protected Visual Environments (IMPROVE) dataset

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[15] United States Forest Service AQRV review of Eagle Cap Visibility Actions Visibility in the Eagle Cap Wilderness is represented by the IMPROVE monitor at the Starkey Experimental Forest. (https://www.fs.fed.us/air/documents/EagleCapWAQRpt-web.pdf)

summaries are shown in Figure 5-3 and Figure 5-5, revealing the relatively small contribution of NO_X-related emissions to overall visibility impacts on both the cleanest and most impaired days, respectively. The emission inventory for the NWP Baker's engines have very little emissions of SO_2 and organic material (represented as VOC). The overall visibility impacts information supports the conclusion that NO_X emission reductions from the NWP Baker engines will not contribute to visibility improvement at Eagle Cap Wilderness Area or Strawberry Mountain Wilderness Area.

Figure 5-3 Starkey Experimental Forest Clearest Days

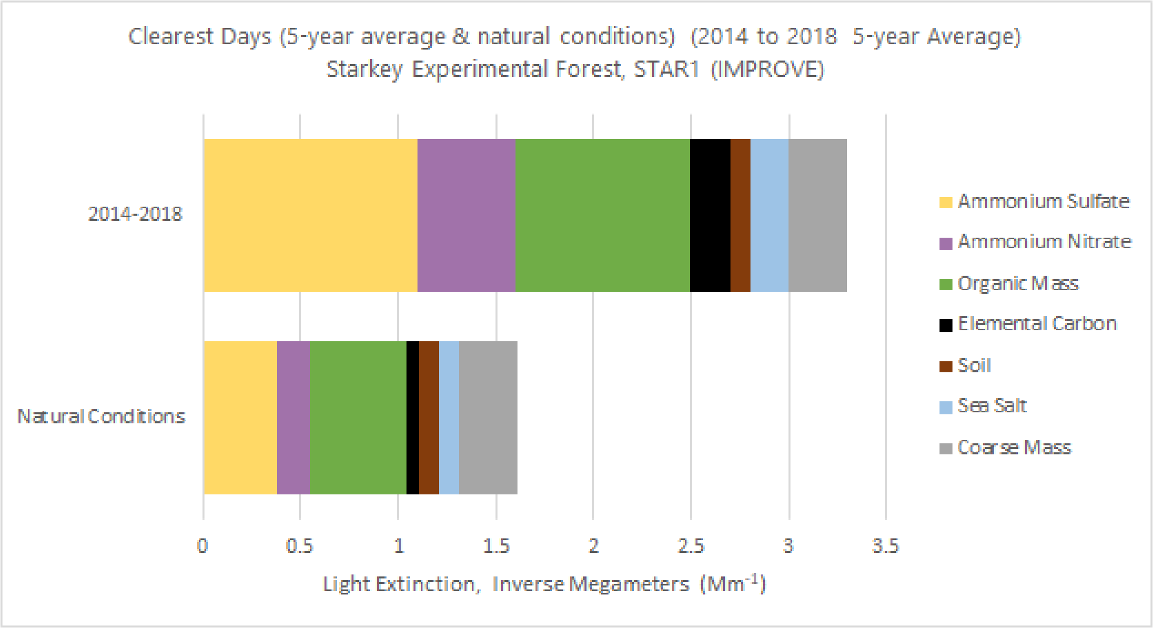
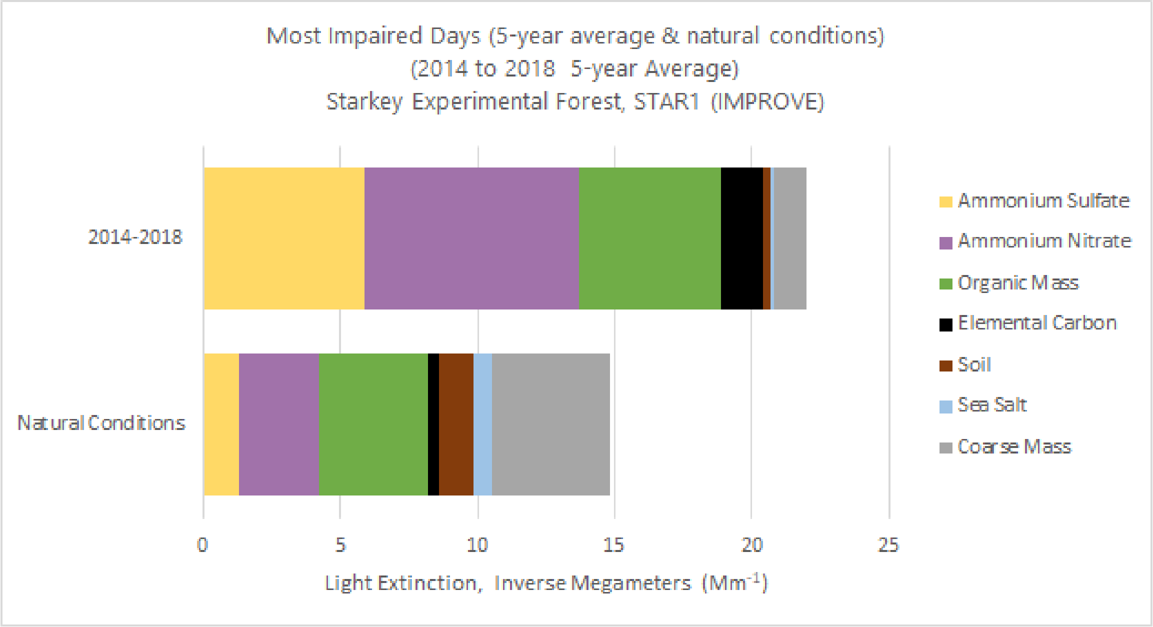
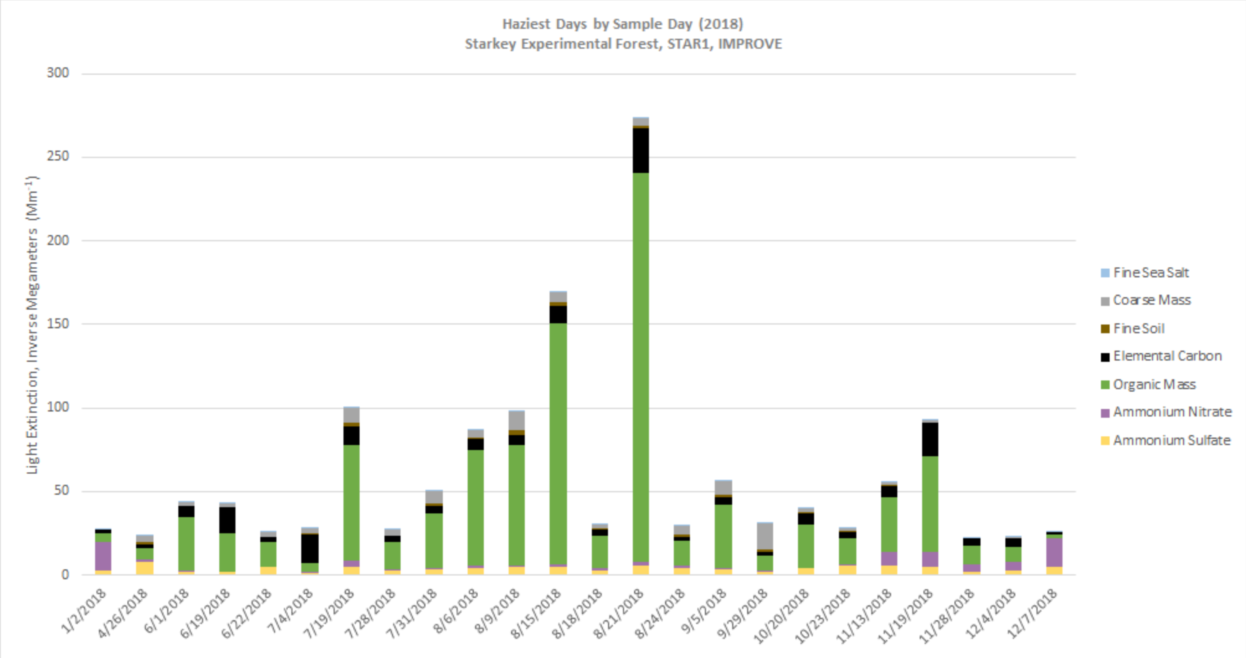


Figure 5-4 Starkey Experimental Forest Most Impaired Days



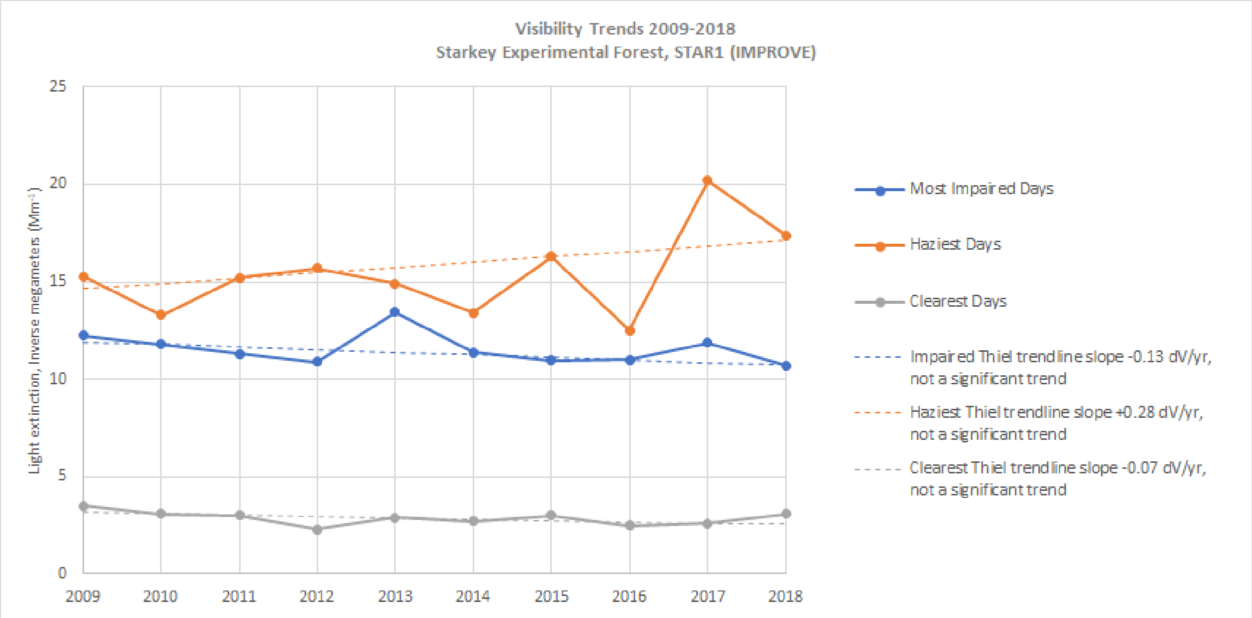
A review of the distribution of 2018's haziest days (Figure 5-5) indicates that NO_X-impacted days (represented by the purple bar – ammonium nitrate) are limited to a small number of days in the winter, with the bulk of haze impacts occurring in the summer months related to Organic mass (green bar) emissions. Additionally, of the haziest days, the worst days are those associated with Organic mass, with NO_X-affected days having notably lower impacts.

Figure 5-5 Starkey Experimental Forest Haziest Days



Overall, visibility trends over the last decade have been relatively flat, with marginal increases on the haziest days identified as "not a significant trend" and slight improvements on the clearest days as a "significant trend" (Figure 5-5). Given the relatively minimal effect of NO_X-related emissions to most of the haziest days, NO_X controls at a relatively small source such as NWP are not likely to provide impactful improvement in visibility impacts on those days.

Figure 5-6 Starkey Experimental Forest Visibility on Haziest and Clearest Days



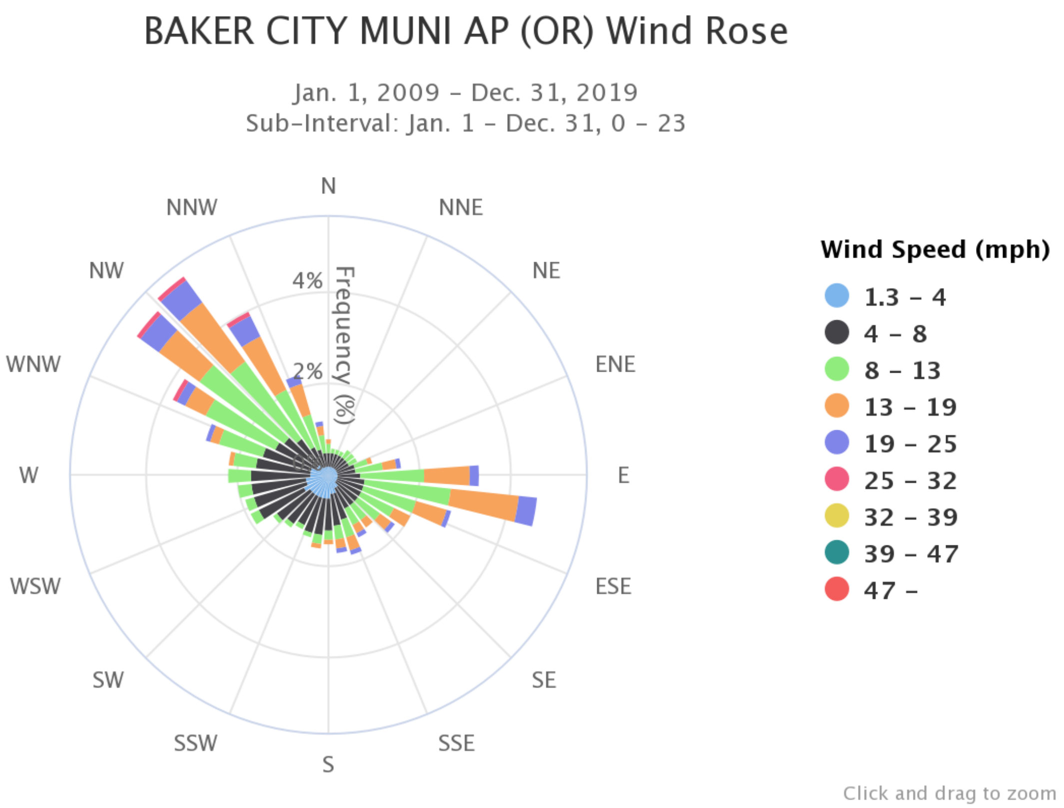
Data source: http://vista.cira.colostate.edu/Improve/rhr-summary-data/

5.3.2 Wind Direction Analysis

In addition to the lack of impact conclusion from the pollutant discussion above, the NWP Baker emissions must be transported from Baker City, Oregon, to the Eagle Cap Wilderness Area (which is located 40 km to the east-northeast/northeast) or the Strawberry Mountain Wilderness Area (which is located 85 km to the southwest to have any direct impact on visibility. A review of the wind rose from the Baker City municipal airport (Figure 5-6) suggests the frequency of winds from the northeast/east-northeast are by far the least frequent (conservatively 1% of the time). The wind rose also suggests winds from the southwest/west-southwest occur less than 5% of the time. Further, the predominant wind direction for this area appears to be from the northwestern quadrant. Even if we consider seasonalimpacts, the wind roses do not indicate any significant change in that depict transport from NWP Baker to Eagle Cap or Strawberry Mountain Wilderness Areas.

Without any further evaluation, the fact that winds toward the Class I areas from this source are very infrequent should allow ODEQ to discount any the potential impact on Eagle Cap and Strawberry Mountain from NWP.

Figure 5-7 Annual Wind Rose for Baker City, OR



5.4 WRAP photochemical modeling inputs

As noted above, ODEQ calculated the screening impacts using the Q/d method, comparing emissions (Q) to distance from the Class I areas (d). For the Eagle Cap, the Q/d for the NWP engines collectively is less than 4.

Ongoing emission inventory development by WRAP's Oil & Gas Work Group (OGWG) for the projected 2028 model inventory[16] projects no change in CO, VOC, and PM, or NOx versus their 2014 baseline inventory[17] for NWP. This means that the WRAP emission inventory projection team considers the projection factor for reciprocating engine emissions in northeastern Oregon, or more specifically, Baker County, to be 1 (i.e., no growth) and there is no presumed emission control required by an existing, or planned, regulation at this time.

OGWG planning documents note that the regional haze modeling is planned to use a continuation of historical trends for the projected future emissions from Oil and Gas sources (the "medium scenario" described in the emission inventory development reports). No significant change in modeled impact from NWP would be expected given the lack of projected change in emissions and the very small actual emissions from the Baker engines. For the purposes of providing the most accurate inventory to be used in the WRAP photochemical modeling, NWP requests that ODEQ provide the revised baseline emission inventory information in Table 4-1 (i.e., the average of the 2014-2018 emissions – 121.36 tons NO_X / year) to the WRAP OGWG for inclusion in the photochemical analysis.

5.5 Visibility Review Summary

Overall, based on the reductions possible from potential NO_X emission controls, NWP has concluded that the visibility impacts can be screened out using existing tools (Q/d) and/or the lack of winds from NWP – Baker to Eagle Cap Wilderness and Strawberry Mountain Wilderness areas (either individually or collectively).

Further, NWP requests ODEQ provide an update to the 2014 baseline emission inventory being developed by WRAP to account for the information provided in Table 4-1.

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[16] WRAP Oil & Gas Work Group. "Projected Emissions from Baseline Year Emissions Inventory – October 11, 2019."
https://www.wrapair2.org/pdf/WESTAR_OGWG_Future_Emissions_Inventory_webdist_101419_nolink.xlsx

[17] WRAP Oil & Gas Work Group. "Baseline Year Alaska and Intermountain Region Emissions Inventory revised final deliverables – Sept. 2019."
https://www.wrapair2.org/pdf/WESTAR_OGWG_Emissions_Inventory_2014_Webdistribution_090919_nolink.xlsx

6 Conclusion

A four-factor analysis and visibility impact review have been conducted for the NWP Baker. This site-specific analysis was conducted to meet the requirements of the second implementation regional haze requirements and goals in 40 CFR 51.308(d)(1).

The analysis considered the following factors as outlined in 40 CFR 51.308(f)(2)(i):

1. The costs of compliance
2. The time necessary for compliance
3. The energy and non-air quality environmental impacts of compliance
4. The remaining useful life of any potentially affected major or minor stationary source or group of sources

The analysis also included a review of the screening conducted by WRAP and an evaluation of the meteorological conditions in northeastern Oregon to determine if there is sufficient cause to conclude NO_X emission reductions at NWP Baker would be beneficial to visibility at Eagle Cap Wilderness Area or Strawberry Mountain Wilderness.

Based on this analysis, NWP Baker has concluded that new emission controls are not warranted because the cost of compliance of technically feasible retrofit emission control technologies is not reasonable and visibility benefits on the haziest days from facility emission reductions are not likely to occur.

Appendix A-1

Combined Control Cost Estimate for EU1 (GMWA-6s)

Appendix A-1 - NOx Control Cost Calculations for EU1 (GMWA-6 Enginges) Combined
Northwest Pipeline, LLC
Table 1 - Cost Evaluation Summary

Control Technology Description

Technology Name		**LEC Retrofit**
Expected Equipment Life (years)	[1]	20
Expected Utilization Rate (% of Capacity)	[1]	100%
Expected Annual Hours of Operation (hr/year)	[1]	1,869
Notes on Technology		

Control Equipment Costs

Capital Costs		
Direct Capital Costs (DC)	[2]	$11,212,500
Indirect Capital Costs (IC)	[2]	$3,027,375
Total Capital Investment (TCI = DC + IC)	[2]	$14,239,875
Total Capital Investment (TCI = DC + IC) with Retrofit Factor	[2]	$14,239,875
Operating Costs		
Direct Operating Costs ($/year)	[3]	$109,772
Indirect Operating Costs ($/year)	[3]	$1,827,042
Total Annual Cost ($/year)	[4]	$1,936,814

NOx Emission Controls

NOx lb/hr while operating

Baseline NOx Emission Rate (ton/year)	[5]	93.66

NOx Control Efficiency (mass%)	[6]	80.00%
Controlled Emission Rate (ton NOx/year)	[7]	18.73
Mass Removed from Exhaust (ton NOx/year)	[8]	74.93
Control Cost Effectiveness ($/ton NOx removed)	[9]	$25,850

Footnotes

[1] Documentation of technology parameters noted

Parameter	
Expected Equipment Life	Assumed
Expected Utilization Rate	Assumed

Appendix A-1 - NOx Control Cost Calculations for EU1 (GMWA-6 Enginges) Combined
Northwest Pipeline, LLC
Table 1 - Cost Evaluation Summary

Expected Hours of Operation	Average operating hours during 2014 - 2019 for EU1

[2] See Table 2 - Capital Costs

[3] See Table 3 - Operating Costs

[4] Total Annual Cost = Direct Operating Costs + Indirect Operating Costs
Class 4 Estimate: Study or Feasibility with -30%/+50% accuracy range according to *AACE International Recommended Practice No. 18R-97, TCM Framework: 7.3 - Cost Estimating and Budgeting, 2005* .

[5] Sum of average emission rates for Units 1-3 in 2014 - 2018

[6]

Documentation of Control Efficiency for each control technology.	Estimated control efficiency for LEC Retrofit from *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines, Technologies & Cost Effectiveness* (Northeast States for Coordinated Air Use Mangement, December 2000)

[7] Controlled Emission Rate = (1 - Control Efficiency) * Baseline Emissions

[8] Mass Removed from Exhaust = Baseline Emissions - Controlled Emission Rate

[9] Control Cost Effectiveness = Total Annual Cost /Mass Removed from Exhaust

Appendix A-1 - NOx Control Cost Calculations for EU1 (GMWA-6 Engings) Combined
Northwest Pipeline, LLC
Table 2 - Capital Costs

Control Technology Description

Technology Name	**LEC Retrofit**
Expected Equipment Life (years)	20

Current Chemical Engineering Plant Cost Index (CEPCI)

CEPCI of Equipment Cost Estimate Year

Direct Capital Costs (DC) **$11,212,500**

Purchased Equipment Costs		
Equipment Costs	[1]	$9,750,000
Instrumentation	[2]	$975,000
Sales Tax	[3]	$0
Freight	[4]	$487,500
Generalized Installation Costs		
Site-Specific Installation Costs		

Indirect Capital Costs (IC) **$3,027,375**

Engineering & Supervision	[5]	$1,121,250
Start-Up Costs	[5]	$112,125
Performance Test	[5]	$112,125
Contingency	[5]	$1,681,875
Contingency - *EPA Air Pollution Control Cost Manual, 7th Edition*	[5]	15%

Retrofit Factor	[6]	1.00
Total Capital Investment (TCI)	[6]	**$14,239,875**
Total Capital Investment (TCI)	[6]	**$14,239,875**

Capital Recovery

Interest Rate	[7]	5.5%
Expected Equipment Life		20
Capital Recovery Factor (CRF)	[8]	8.37%
Adjusted TCI for Capital Recovery	[10]	$14,239,875
Capital Recovery Cost (CRC)	[11]	$1,191,583

Footnotes

Appendix A-1 - NOx Control Cost Calculations for EU1 (GMWA-6 Engignes) Combined
Northwest Pipeline, LLC
Table 2 - Capital Costs

[1]	Documentation of Capital Cost for control technology.	Vendor estimate for LEC Retrofit. Cost is total for all engines and includes installation

[2] Per *EPA Air Pollution Control Cost Manual,* 6th edition, 2002. Section 1, Chapter 2, Table 2.4. Instrumentation ranges between 5% and 30% of the quoted Equipment Cost, with a typical value of

[3] Oregon sales tax is 0% of sale price, applied to the Equipment Costs.

[4] Per *EPA Air Pollution Control Cost Manual,* 6th edition, 2002. Section 1, Chapter 2, Table 2.4. Freight ranges between 1% and 10% of the quoted Equipment Cost, with a typical value of 5%.

[5] Assumed *EPA Air Pollution Control Cost Manual,* 6th edition, 2002, factors from various chapters .

Capital Cost Factors for Control Equipment - Factor applied to Purchased Equipment Cost	
Engineering	0.10
Start-Up	0.01
Performance Test	0.01
Contingency (site-specific)	0.01

[6]

Total Capital Investment (TCI) = Direct Capital Costs (DC) + Indirect Capital Costs (IC).

[7] Per EPA Air Pollution Control Cost Manual, 7th edition, 2019.

[8] Per *EPA Air Pollution Control Cost Manual,* 6th edition, 2002. Section 1, Chapter 2, Equation 2.8a.

$$CRF = \left(\frac{i \times (1+i)^n}{(1+i)^n - 1}\right)$$

Where: i = interest rate

n = number of years

[10] Adjusted TCI for Capital Recovery = TCI - Capital Cost of Replacement Parts

[11] Per *EPA Air Pollution Control Cost Manual,* 6th edition, 2002. Section 1, Chapter 2, Equation 2.8.

$$CRC = NPV \times CRF$$

In this case, the Net Present Value (NPV) factor is replaced with the TCI for the control technology.

[12] Documentation of other items which should be included in the capital cost, but may not be covered by the Purchased Equipment Costs, Generalized Installation Costs, or Indirect Capital Costs.

Appendix A-1 - NOx Control Cost Calculations for EU1 (GMWA-6 Engings) Combined
Northwest Pipeline, LLC
Table 3 - Operating Costs

Control Technology Description

Technology Name	**LEC Retrofit**
Expected Utilization Rate (%)	100%
Expected Annual Hours of Operation (hr/year)	1,869
Notes on Technology	

Direct Annual Costs (DAC, $/year) **$109,772**

Operating Labor			
Operator	Worked Hours Per Year (hr/year)	[1]	548
	Cost Per Hour ($/hr)	[2]	$63.65
	Cost Per Year ($/year)	[3]	$34,848
Supervisor	Cost Per Year ($/year)	[4]	$5,227
Maintenance			
Labor	Worked Hours Per Year (hr/year)	[5]	548
	Cost Per Hour ($/hr)	[2]	$63.65
	Cost Per Year ($/year)	[3]	$34,848
Materials	Cost Per Year ($/year)	[6]	$34,848

Indirect Annual Costs (IAC, $/year) **$1,827,042**

Overhead	[7]	$65,863
Administration	[8]	$284,798
Property Tax	[9]	$142,399
Insurance	[10]	$142,399
Capital Recovery for Replacement Parts	[11]	
Capital Recovery	[12]	$1,191,583

Total Annual Costs (TAC = DAC + IAC, $/year) **$1,936,814**

Footnotes

[1] Assumed 0.5 hours per 8 hr shift
[2] See 'Table 5 - Raw Material, Utility, and Waste Disposal Costs' for details.
[3] Cost per year = Demand/year * Retail Price
[4] 15% of operator costs per *EPA Air Pollution Control Cost Manual,* 6th Ed., 2002.
[5] Assumed 0.5 hours per 8 hr shift
[6] 100% of maintenance labor per *EPA Air Pollution Control Cost Manual,* 6th Ed., 2002.
[7] Overhead estimated as 60% of total labor and maintenance materials per *EPA Air Pollution Control Cost Manual,* 6th Ed., 2002.
[8] Administration estimated as 2% of Total Capital Investment (TCI) per *EPA Air Pollution Control Cost Manual,* 6th Ed., 2002.
[9] Property tax estimated as 1% of Total Capital Investment (TCI) per *EPA Air Pollution Control Cost Manual,* 6th Ed., 2002.
[10] Insurance estimated as 1% of Total Capital Investment (TCI) per *EPA Air Pollution Control Cost Manual,* 6th Ed., 2002.
[11] See 'Table 4 - Replacement Parts' for details.
[12] See 'Table 2 - Capital Costs ' for details.

Appendix A-1 - NOx Control Cost Calculations for EU1 (GMWA-6 Engignes) Combined
Northwest Pipeline, LLC
Table 5 - Raw Material, Utility, and Waste Disposal Costs

Labor Costs

Occupation	*Cost Per Unit*	*Unit*	*Year Basis*	*Footnote*	*Cost Index*	*Cost Index for Base Year*	*Cost Index for 2020*	*Adjusted Cost ($/Unit)*
Operator/Maintenance/Supervisory	$60.00	hour	2018	[1]	Assume 3% Inflation	100	106	$63.65

Footnotes

[1] 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.

Appendix A-2

Combined Control Cost Estimate for EU2 (GMVH-8)

Appendix A-2 - NOx Control Cost Calculations for EU2 (GMVH-8 Engine)
Northwest Pipeline, LLC
Table 1 - Cost Evaluation Summary

Control Technology Description

Technology Name		**LEC Retrofit**
Expected Equipment Life (years)	[1]	20
Expected Utilization Rate (% of Capacity)	[1]	100%
Expected Annual Hours of Operation (hr/year)	[1]	2,388

Control Equipment Costs

Capital Costs		
Direct Capital Costs (DC)	[2]	$2,242,500
Indirect Capital Costs (IC)	[2]	$605,475
Total Capital Investment (TCI = DC + IC)	[2]	$2,847,975
Total Capital Investment (TCI = DC + IC) with Retrofit Factor	[2]	$2,847,975
Operating Costs		
Direct Operating Costs ($/year)	[3]	$109,772
Indirect Operating Costs ($/year)	[3]	$418,099
Total Annual Cost ($/year)	[4]	$527,871

NOx Emission Controls

NOx lb/hr while operating

Baseline NOx Emission Rate (ton/year)	[5]	27.22

NOx Control Efficiency (mass%)	[6]	80.00%
Controlled Emission Rate (ton NOx/year)	[7]	5.44
Mass Removed from Exhaust (ton NOx/year)	[8]	21.77
Control Cost Effectiveness ($/ton NOx removed)	[9]	$24,243

Footnotes

[1] Documentation of technology parameters noted

Parameter	
Expected Equipment Life	Assumed
Expected Utilization Rate	Assumed

Appendix A-2 - NOx Control Cost Calculations for EU2 (GMVH-8 Engine)

Northwest Pipeline, LLC

Table 1 - Cost Evaluation Summary

Expected Hours of Operation	Average operating hours during 2014 - 2019 for EU2

[2] See Table 2 - Capital Costs

[3] See Table 3 - Operating Costs

[4] Total Annual Cost = Direct Operating Costs + Indirect Operating Costs
Class 4 Estimate: Study or Feasibility with -30%/+50% accuracy range according to *AACE International Recommended Practice No. 18R-97, TCM Framework: 7.3 - Cost Estimating and*

[5] Average emission rate 2014-2019

[6]

Documentation of Control Efficiency for each control technology.	Estimated control efficiency for LEC Retrofit from *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines, Technologies & Cost Effectiveness* (Northeast States for Coordinated Air Use Mangement, December 2000)

[7] Controlled Emission Rate = (1 - Control Efficiency) * Baseline Emissions

[8] Mass Removed from Exhaust = Baseline Emissions - Controlled Emission Rate

[9] Control Cost Effectiveness = Total Annual Cost /Mass Removed from Exhaust

Appendix A-2 - NOx Control Cost Calculations for EU2 (GMVH-8 Engine)
Northwest Pipeline, LLC
Table 2 - Capital Costs

Control Technology Description

Technology Name	LEC Retrofit
Expected Equipment Life (years)	20

Current Chemical Engineering Plant Cost Index (CEPCI)
CEPCI of Equipment Cost Estimate Year

Direct Capital Costs (DC)		**$2,242,500**
Purchased Equipment Costs		
Equipment Costs	[1]	$1,950,000
Instrumentation	[2]	$195,000
Sales Tax	[3]	$0
Freight	[4]	$97,500
Generalized Installation Costs		
Site-Specific Installation Costs		

Indirect Capital Costs (IC)		**$605,475**
Engineering & Supervision	[5]	$224,250
Start-Up Costs	[5]	$22,425
Performance Test	[5]	$22,425
Contingency	[5]	$336,375
Contingency - *EPA Air Pollution Control Cost Manual, 7th Edition*	[5]	15%

Retrofit Factor	[6]	1.00
Total Capital Investment (TCI)	[6]	**$2,847,975**
Total Capital Investment (TCI)	[6]	**$2,847,975**

Capital Recovery

Interest Rate	[7]	5.5%
Expected Equipment Life		20
Capital Recovery Factor (CRF)	[8]	8.37%
Adjusted TCI for Capital Recovery	[10]	$2,847,975
Capital Recovery Cost (CRC)	[11]	$238,317

Footnotes

Appendix A-2 - NOx Control Cost Calculations for EU2 (GMVH-8 Engine)
Northwest Pipeline, LLC
Table 2 - Capital Costs

[1]	Documentation of Capital Cost for control technology.	Vendor estimate for LEC Retrofit. Cost includes labor contractor labor expenses.

[2] Per *EPA Air Pollution Control Cost Manual,* 6th edition, 2002. Section 1, Chapter 2, Table 2.4. Instrumentation ranges between 5% and 30% of the quoted Equipment Cost, with a typical value of

[3] Oregon sales tax is 0% of sale price, applied to the Equipment Costs.

[4] Per *EPA Air Pollution Control Cost Manual,* 6th edition, 2002. Section 1, Chapter 2, Table 2.4. Freight ranges between 1% and 10% of the quoted Equipment Cost, with a typical value of 5%.

[5] Assumed *EPA Air Pollution Control Cost Manual,* 6th edition, 2002, factors from various chapters .

Capital Cost Factors for Control Equipment - Factor applied to Purchased Equipment Cost	
Engineering	0.10
Start-Up	0.01
Performance Test	0.01
Contingency (site-specific)	0.01

[6]

Total Capital Investment (TCI) = Direct Capital Costs (DC) + Indirect Capital Costs (IC).

[7] Per EPA Air Pollution Control Cost Manual, 7th edition, 2019.

[8] Per *EPA Air Pollution Control Cost Manual,* 6th edition, 2002. Section 1, Chapter 2, Equation 2.8a.

$$CRF = \left(\frac{i \times (1+i)^n}{(1+i)^n - 1}\right)$$

Where: i = interest rate

n = number of years

[10] Adjusted TCI for Capital Recovery = TCI - Capital Cost of Replacement Parts

[11] Per *EPA Air Pollution Control Cost Manual,* 6th edition, 2002. Section 1, Chapter 2, Equation 2.8.

$$CRC = NPV \times CRF$$

In this case, the Net Present Value (NPV) factor is replaced with the TCI for the control technology.

[12] Documentation of other items which should be included in the capital cost, but may not be covered by the Purchased Equipment Costs, Generalized Installation Costs, or Indirect Capital Costs.

Appendix A-2 - NOx Control Cost Calculations for EU2 (GMVH-8 Engine)
Northwest Pipeline, LLC
Table 3 - Operating Costs

Control Technology Description

Technology Name	LEC Retrofit
Expected Utilization Rate (%)	100%
Expected Annual Hours of Operation (hr/year)	2,388
Notes on Technology	

Direct Annual Costs (DAC, $/year) **$109,772**

Operating Labor			
Operator	Worked Hours Per Year (hr/year)	[1]	548
	Cost Per Hour ($/hr)	[2]	$63.65
	Cost Per Year ($/year)	[3]	$34,848
Supervisor	Cost Per Year ($/year)	[4]	$5,227
Maintenance			
Labor	Worked Hours Per Year (hr/year)	[5]	548
	Cost Per Hour ($/hr)	[2]	$63.65
	Cost Per Year ($/year)	[3]	$34,848
Materials	Cost Per Year ($/year)	[6]	$34,848

Indirect Annual Costs (IAC, $/year) **$418,099**

Overhead	[7]	$65,863
Administration	[8]	$56,960
Property Tax	[9]	$28,480
Insurance	[10]	$28,480
Capital Recovery for Replacement Parts	[11]	
Capital Recovery	[12]	$238,317

Total Annual Costs (TAC = DAC + IAC, $/year) **$527,871**

Footnotes

[1] Assumed 0.5 hours per 8 hr shift
[2] See 'Table 5 - Raw Material, Utility, and Waste Disposal Costs' for details.
[3] Cost per year = Demand/year * Retail Price
[4] 15% of operator costs per *EPA Air Pollution Control Cost Manual,* 6th Ed., 2002.
[5] Assumed 0.5 hours per 8 hr shift
[6] 100% of maintenance labor per *EPA Air Pollution Control Cost Manual,* 6th Ed., 2002.
[7] Overhead estimated as 60% of total labor and maintenance materials per *EPA Air Pollution Control Cost Manual,* 6th Ed., 2002.
[8] Administration estimated as 2% of Total Capital Investment (TCI) per *EPA Air Pollution Control Cost Manual,* 6th Ed., 2002.
[9] Property tax estimated as 1% of Total Capital Investment (TCI) per *EPA Air Pollution Control Cost Manual,* 6th Ed., 2002.
[10] Insurance estimated as 1% of Total Capital Investment (TCI) per *EPA Air Pollution Control Cost Manual,* 6th Ed., 2002.
[12] See 'Table 2 - Capital Costs ' for details.

Appendix A-2 - NOx Control Cost Calculations for EU2 (GMVH-8 Engine)
Northwest Pipeline, LLC
Table 5 - Raw Material, Utility, and Waste Disposal Costs

Labor Costs

Occupation	*Cost Per Unit*	*Unit*	*Year Basis*	*Footnote*	*Cost Index*	*Cost Index for Base Year*	*Cost Index for 2020*	*Adjusted Cost ($/Unit)*
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Footnotes

[1] 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.