REGIONAL HAZE
FOUR-FACTOR ANALYSIS

Interfor US, Inc.
Gilchrist Facility

Prepared on behalf of:

Interfor US, Inc.
Gilchrist Facility
#1 Sawmill Road
Gilchrist, OR 97737

Prepared by:

3143 E. Lyndale Ave.
Helena, MT 59601
(406) 442-5768
www.bison-eng.com

May 19, 2020

EXECUTIVE SUMMARY

Bison Engineering, Inc. (Bison) was retained by Interfor US, Inc. (Interfor) to prepare a four-factor analysis on potential regional haze precursor emission controls at their sawmill facility located in Gilchrist, Oregon. The four-factor analysis was requested by the Oregon Department of Environmental Quality (ODEQ) in a certified letter dated December 23, 2019.

The analysis itself relates to “Round 2” of development of a State Implementation Plan (SIP) to address regional haze. Regional haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308. The purpose of the four-factor analysis is to determine if there are emission control options at Interfor that, if implemented, could be used to attain “reasonable progress” toward the State’s visibility goals.

The four-factor analysis was conducted for control of sulfur dioxide (SO_2), oxides of nitrogen (NO_x) and particulate matter less than ten micrometers (PM_{10}) emissions. The four-factor analysis produced a cost effectiveness value for adding equipment to control NO_x and PM_{10} emissions from the biomass-fired boilers. The analysis showed that the cost effectiveness for additional emission controls is not considered economically feasible. Information is also provided showing that additional emissions controls at the Interfor site in Gilchrist, Oregon would not help reduce visibility impairment in nearby Class I areas.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF APPENDICES

ACRONYMS

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Btu	British thermal unit
CAA	Clean Air Act
CEPCI	Chemical Engineering Plant Cost Index
CFR	Code of Federal Regulations
Control Cost Manual	EPA Air Pollution Control Cost Manual
DPW	Diamond Peak Wilderness
dV	Deciview
EPA	Environmental Protection Agency
HHV	Higher Heating Value
IMPROVE	Interagency Monitoring of Protected Visual Environments
Interfor	Interfor US, Inc.
lb/MMBtu	Pounds per million British thermal units
lb/hr	Pounds per hour
MMBtu/hr	Million British thermal units per hour
MMBtu/MWh	Million British thermal units per megawatt-hour
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NACAA	National Association of Clean Air Agencies
NH_3	Ammonia
$(NH_4)_2SO_4$	Ammonium sulfate
NPHR	Net plant heat input rate
NSR	Normalized stoichiometric ratio
NO	Nitric oxide
NO_2	Nitrogen dioxide
NO_x	Oxides of nitrogen
PM	Particulate matter
PM_{10}	Particulate matter less than ten micrometers
ODEQ	Oregon Department of Environmental Quality
RHR	Regional Haze Rule
Round 1	First planning period of the Regional Haze Program
Round 2	Second (current) planning period of the Regional Haze Program
RPG	Reasonable progress goals
SCR	Selective catalytic reduction
SIP	State Implementation Plan
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
TPY	Tons per year
TSD	2008 Electric Generating Unit NO_x Mitigation Strategies Proposed Rule Technical Support Document
USGS	United States Geographical Survey
UTM	Universal Transverse Mercator
WRAP	Western Regional Air Partnership

1.0 INTRODUCTION

1.1 Basis of Four-Factor Analysis Request

As part of the 1977 amendments to the Federal Clean Air Act (42 USC 7401 *et. seq.*) Congress declared as a national goal "… the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution." (42 USC 7491(a)(1)). With that goal, plans and requirements were eventually codified in the Code of Federal Regulations (CFR) primarily in 40 CFR 51.308. (The entire visibility program is found in 40 CFR 51.300 to 309). These regulations require States to establish "reasonable progress goals" in order to "attain natural visibility conditions" by the year 2064 (40 CFR 51.308(d)(1)).

Since the Federal visibility rules were revised in 1999 to address regional haze, Oregon DEQ has submitted numerous revisions to their State Implementation Plan (SIP) to the Environmental Protection Agency (EPA) for review, approval, and incorporation into the State's SIP to address regional haze. During the reasonable progress analysis portion of the first planning period (Round 1), ODEQ focused on NO_x, SO_2, and organic carbon emissions as the key pollutants contributing to regional haze (77 FR 30454; see also 76 FR 38997 and 77 FR 50611).

Organic carbon was determined to result primarily from wildfire, and at the time, ODEQ determined that PM from point sources contributed only a minimal amount to visibility impairment in Oregon Class I areas. Therefore, ODEQ focused on NO_x and SO_2 controls for point source emissions during the Round 1 reasonable progress analysis and ultimately concluded that it was not reasonable to require controls on point sources for those emissions at the time. ODEQ did not specifically review the Interfor Gilchrist Facility for visibility impairment contribution during the Round 1 reasonable progress analysis.

A second round of obligations (Round 2) is now under development. Round 2, or planning period as it is sometimes referred, requires an additional step toward 'reasonable progress' in meeting the national goal of attaining natural visibility conditions in mandatory Class I areas by 2064. Based on monitoring data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) program [1] and consistent with other Western Regional Air Partnership (WRAP)[1] states, ODEQ chose to address NO_x, SO_2, and PM_{10} as components of facility-level emissions to be considered for reduction as part of the Round 2 reasonable progress analysis. ODEQ found that these three species dominate visibility impairment at Oregon Class I areas.

The Regional Haze Rule (RHR) as outlined in 40 CFR 51.308 *et seq*. identifies four factors which should be considered in evaluating potential emission control measures to make

---

[1] The Western Regional Air Partnership, or WRAP, is a voluntary partnership of states, tribes, federal land managers, local air agencies and the US EPA whose purpose is to understand current and evolving regional air quality issues in the West. https://www.wrapair2.org/

reasonable progress toward the visibility goal. These four factors are collectively known as the four-factor analysis and are as follows:

- *Factor 1*. Cost 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 any existing source subject to such requirements

ODEQ contacted the Interfor Gilchrist Facility by certified letter dated December 23, 2019, establishing the requirement to provide pollutant-specific information and an analysis of the above listed four factors for every emission point at the facility (Appendix A).

1.2 Sawmill Facility Information

Interfor owns and operates a sawmill located in Gilchrist, Oregon which is regulated under ODEQ Title V Operating Permit Number 18-0005-TV-01. As described in the Title V Permit Review Report, the facility consists of a sawmill, planing mills, lumber dry kilns, and a steam plant. Boilers in the steam plant provide the steam used to heat the dry kilns. The two main steam plant boilers burn hogged wood and bark (hog fuel) to create steam. The facility equipment and emissions are discussed in detail in Section 4.0 of this report.

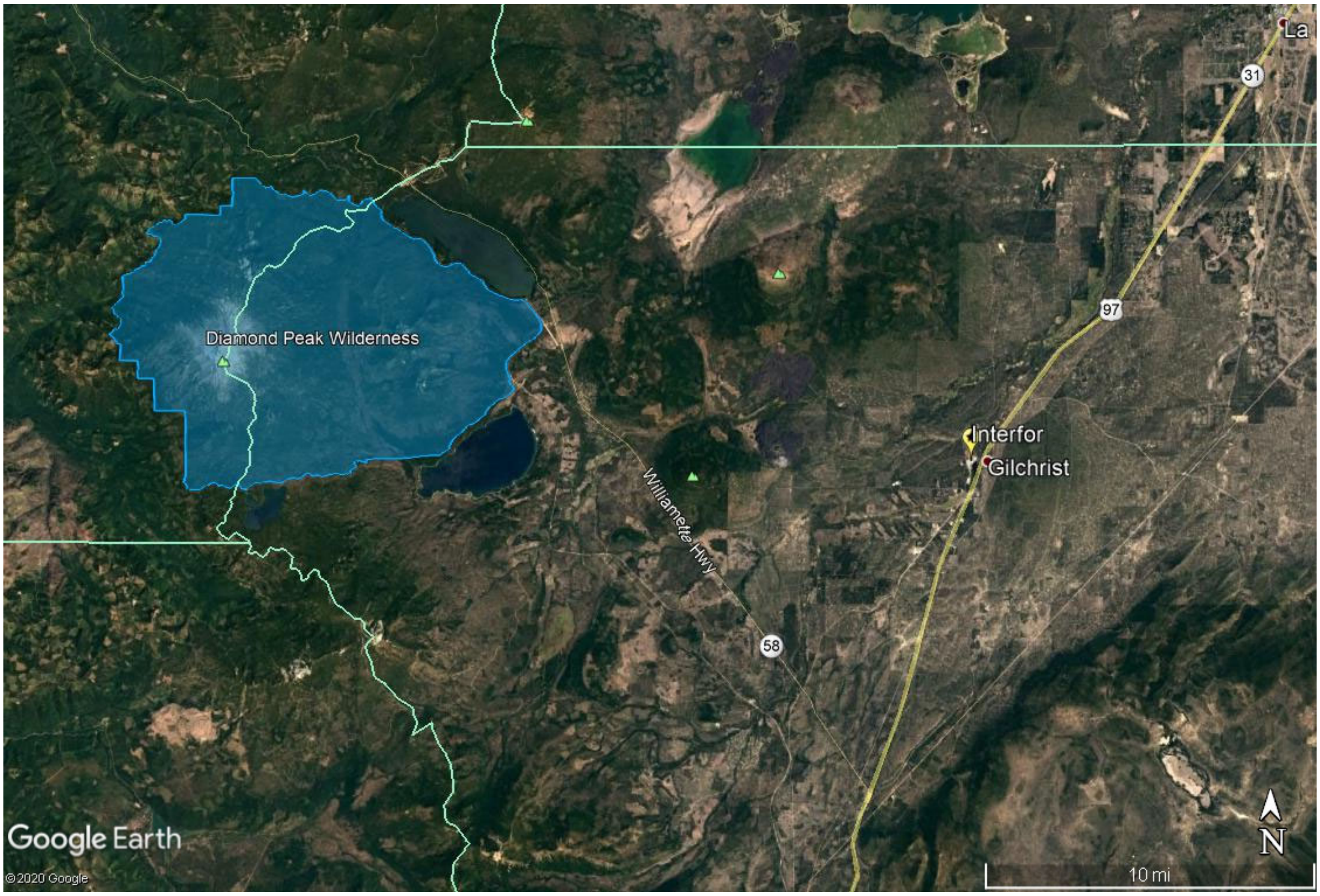
1.3 Facility Location Information

The Interfor mill site is located at #1 Sawmill Road in Gilchrist, Oregon. The legal description of the site location is S½ of Section 19, Township 24 South, Range 9 East, in Klamath County, Oregon. The Universal Transverse Mercator (UTM) coordinates of the boiler stack are Zone 10 T, WGS 84 datum, easting 605,702 meters (m), and northing 4,814,640 m. The geographical coordinates are 43.477210 (north) latitude and -121.693022 (west) longitude[2]. The site elevation is approximately 4,560 feet above mean sea level.**Error! Reference source not found.** Figure 1-1 shows the site location in relation to the Diamond Peak Wilderness Class I area. The Diamond Peak Wilderness extends to the area between the two lakes due East of Diamond Peak and is the nearest Class I area to the Interfor Gilchrist facility.

---

[2] Site coordinates based on boiler stack location, as shown in Google Earth.

Figure 1-1: Map of Site in Relation to Nearest Class I Area



1.4 Four-Factor Analysis Basis

In accordance with the certified letter from ODEQ dated December 23, 2019, the Interfor Gilchrist Facility was selected for the four-factor analysis based on a “Q/d” analysis. The “Q/d” analysis is used by EPA and all states as a screening tool to determine which sites will be analyzed for Round 2 of the Regional Haze program.

For Round 2, ODEQ has elected to look for reductions in SO_2 and NO_x (precursors to ammonium sulfate and ammonium nitrate) emissions. ODEQ has also included PM_{10} in the regional haze analysis. The sources chosen for the analysis are those facilities whose emissions-to-distance (from the Class I area) ratio exceeds the specified Q/d value as noted below:

If Q/d > 5, then the facility is required to perform a four-factor analysis

Q = combined plant site emission limits (PSEL) for PM_{10}, SO_2 and NO_x (351 tons per year)

d = distance to the nearest mandatory Class I area (22.3 kilometers)

The calculated Q/d ratio for the Gilchrist facility and Diamond Peak Wilderness is 15.7, indicating that the facility could potentially be contributing to visibility impairment and may require further analysis.

The Interfor Gilchrist Facility has a Q/d value of 15.74 based on PSELs and the distance to Diamond Peak Wilderness (22.3 km). PSELs are the plant site emission limits and are higher than the actual reported emissions. The Q/d value was also calculated based on the actual facility emissions as reported in the 2017 National Emissions Inventory and found to be 8.42. The Interfor Gilchrist Facility would be included in the four-factor analysis requirement based on either actual or potential emissions.

The initial Q/d analysis used to trigger the four-factor analysis requirement was based on the emissions for the entire facility, but the four-factor analysis is focused on individual emission sources. The largest source of SO_2, NO_x and PM_{10} emissions at the facility are the hog fuel boilers, B-1 and B-2. The Q/d for the hog fuel boilers alone would exceed the Round 2 threshold.

2.0 PROGRAM SUMMARY AND STATUS

As previously stated, the Regional Haze program is an attempt to attain ‘natural’ (nonanthropogenic) visibility conditions in all mandatory Class I areas[3] by 2064. The RHR itself was promulgated in substantially its current form in 1999 with adjustments made in 2017. The rule has been implemented in incremental steps. The first step, sometimes referred to as the 1st planning period (Round 1), was a combination of BART and a four-factor analysis toward Reasonable Progress Goals (RPGs). During this initial planning period BART applied to certain older facilities, and the four-factor program applied to ‘larger’ facilities that had the potential to impact visibility in a mandatory Class I area. Interfor was excluded from both analyses under Round 1.

2.1 Oregon Initiatives

Round 1 regional haze requirements were implemented in a revision to the Oregon State Implementation Plan (SIP) which was submitted on December 20, 2010. Given the timeframe for Round 1 has expired, the RHR now requires the implementation of Round 2. Round 2 is meant to show an incremental progress toward the national goal for the 10-year period 2018 to 2028. Additional 10-year implementation periods will follow until the national goal is achieved (40 CFR 51.308(f)).

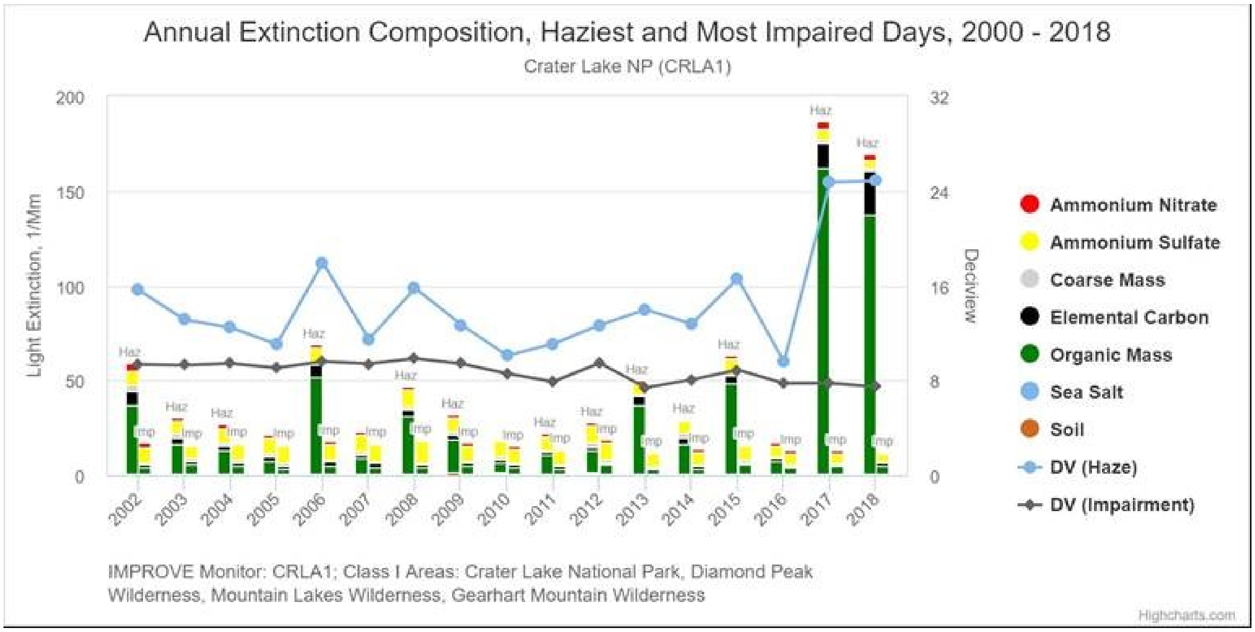
To implement the program fully, it was first necessary to measure regional haze (visibility and its constituents) in the identified Class I areas. This has been an ongoing effort via various ambient monitoring programs including the IMPROVE program [1]. This visibility monitoring program began in 1988 and continues to be a cooperative effort between EPA and various federal land managers (primarily the National Park Service and the US Forest Service). The IMPROVE station at Crater Lake is considered representative of the Diamond Peak Wilderness Area.

Figure 2-1 shows a summary of the IMPROVE monitoring data at the Crater Lake National Park station for the years 2000 through 2018. The results of the IMPROVE monitoring have indicated that the primary pollutants that account for the most anthropogenic (human-caused) visibility degradation are (ammonium) sulfate and (ammonium) nitrate [2]. The primary pollutant that accounts for most non-anthropogenic visibility degradation is organic carbon matter. Wildfire smoke is the major source of organic carbon matter in the air. Organic carbon is the largest contributor to light extinction at nearly all sites on the worst days, while sulfates are the largest contributor to light extinction on the best days. The large contribution of organic carbon is likely due to summer wildfire activity.

---

[3] A mandatory Class I area is usually a national park or wilderness area above a certain threshold size (4,000 or 5,000 acres) and in existence on or before August 7, 1977.

Figure 2-1: IMPROVE Visibility Data for Crater Lake National Park



2.2 Federal Initiatives

Because this request for information arises from the RHR, it is important to understand the nature and purpose of the visibility protection program to properly implement the criteria that will lead to the selection of specific reasonable progress requirements.

A visibility program aimed at attaining national visibility goals in mandatory Class I areas was authorized in Section 169A of the Clean Air Act (42 USC 7491). The national goals are to be attained by the year 2064, approximately 44 years from now. The rules which are to implement this goal of protecting visibility are found at 40 CFR 51, Subpart P (subsections 300 through 309). A review of Subpart P indicates the purpose and goals of the program. The purposes of the program are as follows:

> "*The primary purposes of this subpart are . . .to assure* ***reasonable progress*** *toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment* ***results*** *from manmade air pollution. . .*"
> [40 CFR 51.300(a), emphasis added].

The visibility program may be thought of as the implementation of two sub-programs. One regards new source review permitting and the other addresses "regional haze." Regional haze may further be broken down into the BART program and the reasonable progress program. The underlying reason for this review of the Gilchrist facility's emissions relates to reasonable progress achieved through the four-factor analysis.

In that regard, the RHR outlines what it refers to as "the core requirements" for the implementation of the regional haze goals. More specifically, 40 CFR 51.308(d)(1) states:

> “*For each mandatory Class I Federal area..., the State must establish goals... that provide for reasonable progress towards achieving natural visibility conditions.* ***The reasonable progress goals must provide for an improvement in visibility*** *for the most impaired days...”* [emphasis added]

The rules go on to provide the states with a list of what must be considered in developing reasonable progress. Among these details are the four-factor analysis that is outlined above in Section 1.1 and in the December 23, 2019 letter (Appendix A).

2.3 Applicability for Interfor - Gilchrist

Oregon is tasked with establishing a plan for reasonable progress in carrying out the visibility protection. ODEQ notified the Interfor Gilchrist facility that they must “*complete a four factor analysis of potential additional controls of haze precursor emissions”* which will be evaluated by Oregon (and ultimately EPA) for applicability in establishing a set of specific, reasonable Oregon control strategies that create reasonable progress toward the 2064 goals.

The purpose of the program is to protect visibility by remedying, reducing, and preventing man-made impairments (or activities) over time in mandatory Class I areas. Reasonable progress expresses the notion that states must have implementation plans to approach the national goal by 2064 along a ‘glide-path’ of improvements to visibility, with certain exceptions. Based on the language contained in 40 CFR 51.308(d)(1), it can be ascertained that any activity, remedy or control (proposed or otherwise) that does not reasonably improve visibility in a mandatory Class I area is not a rational candidate for those reasonable progress goals [3]. That sentiment is confirmed in Section II.A EPA August 20, 2019 guidance [4]:

> *“The CAA and the Regional Haze Rule provide a process for states to follow to determine what is necessary to make reasonable progress in Class I areas. As a general matter, this process involves a state evaluating what emission control measures for its own sources, groups of sources, and/or source sectors are necessary in light of the four statutory factors, five additional considerations specified in the Regional Haze Rule, and possibly other considerations (e.g., visibility benefits of potential control measures, etc.). States have discretion to balance these factors and considerations in determining what control measures are necessary to make reasonable progress.”*

As a result, an analysis that only considers one or more emission control options is not enough for inclusion into reasonable progress mandates unless those emission controls are expected to improve actual visibility in a Class I area in a discernible manner. It is neither necessary nor appropriate to include an emission control as part of a reasonable progress goal or plan without a reasonable expectation of a resulting improvement in regional haze as a direct result of the application of the control (i.e., a discernible improvement in deciviews[4] in a Class I area).

To that end, Interfor has elected to not only analyze various control "options" utilizing four factors but has also included a qualitative analysis of impacts the Gilchrist facility may have on the closest Class I Area, Diamond Peak Wilderness. This was accomplished to determine if either the current configuration or future control options would fulfill the underlying need of the program to "***provide for an improvement in visibility*"** at a mandatory Class I area [5].

---

[4] The definition of a deciview is as follows: Deciview haze index=10 ln (b_{ext}/10 Mm^{-1}), where b_{ext} is the atmospheric light extinction coefficient, expressed in inverse megameters (Mm^{-1}). This is taken from the definition found in 40 CFR 51.301. There are, of course, numerous articles and explanations for the deciview metric. One article may be found in the publication "IMPROVE," Volume 2, No. 1, April 1993 which was written by Pitchford and Malm, 1993. From a non-mathematical point of view, the change in deciview of "1" is intended to represent a "just noticeable change" (or sometimes referred to as 'just discernible') in visibility regardless of the baseline visibility.

3.0 REASONABLE PROGRESS PERSPECTIVE

This report has so far provided a summary of the overall regional haze program and the nature of Round 2 implementation. It has also outlined the program's basic elements and background. The following section describes historical emissions trends and the efforts already taken to reduce emissions nationally and in Oregon.

3.1 National Emissions

A national downward trend of industrial PM_{10}, SO_2, and NO_x emissions has been observed over the past 30-years. Reductions in emissions can be attributed to new requirements in the Federal Clean Air Act, advancements within state air quality regulatory programs, improvements in control technology, and the shutdown of industrial facilities. Figure 3-1 depicts national emissions trends from 1990 to 2018.[5]

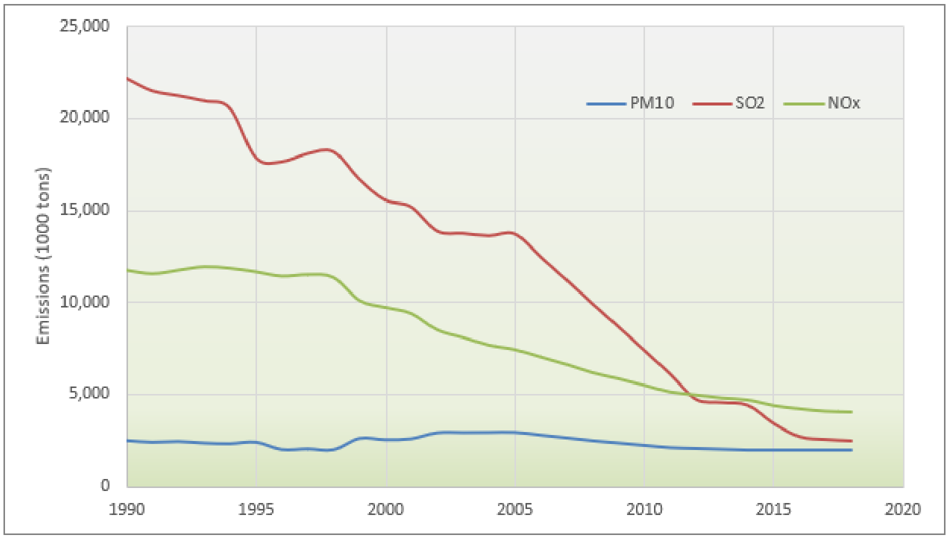
Substantial reductions in industrial emissions of SO_2 and NOx are observed since the promulgation of the RHR in 1999. National PM_{10} emissions from industrial sources have also decreased since 1999 however at a less significant rate. From a national perspective, emissions of SO_2 and NO_x are clearly on a fast-downward trend. National industrial emissions will not likely achieve "zero" by 2064, however their trendlines indicate that, if possible, emissions would be on a rapid pace to achieve zero well before the national goal year. Regardless, substantial reductions have occurred and will likely continue. Due to the emissions reductions that occur in response to other regulatory programs, national emissions contributing to regional haze are anticipated to continue to decline independently of the regional haze related programs.

Irrespective of the visibility impact of these emissions reductions, national SO_2 emissions from industrial sources in 2018 are about 16% of those emissions in 2000 and only about 11% of those emissions during the year the national goal was established (1990). Likewise, national NO_x emissions from industrial sources in 2018 are about 42% of those emissions in 2000 and 35% of those in 1990. Therefore, the reduction of industrial emissions in regard to the Regional Haze program appears to be well ahead of the goal year (2064) on a national level. As is discussed below, emissions reductions in the state of Oregon are also on target to meet the goal.

---

[5] National industrial emissions data obtained from the EPA National Emissions Inventory (NEI) National Emissions Trends database. https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data

Figure 3-1: National Industrial Emission Trends of PM_{10}, SO_2 and NOx (1990 – 2018)



Figures 3-2 and 3-3 provide emissions from categorized "source groups" represented within the NEI national trends data. This provides context into the amount each group contributes to the national total in relation to industrial emissions. The source groups are categorized as shown in Table 3-1.

Table 3-1: NEI Source Group Categorization

Category	NEI Source Groups
Industrial	Fuel Combustion: Electric Utility Fuel Combustion: Industrial Fuel Combustion: Other Chemical and Allied Product Manufacturing Metals Processing Petroleum and Related Industries Other Industrial Processes Solvent Utilization Storage and Transport Waste Disposal and Recycling
Mobile/Transportation	Highway Vehicles Off-Highway
Fire	Wildfire Prescribed Burns
Miscellaneous[6]	Agriculture and Forestry Other Combustion (*excluding forest fires*) Catastrophic/Accidental Releases Repair Shops Health Services Cooling Towers Fugitive Dust

---

[6] Miscellaneous source categories are listed in Table 4.1-2 of the Procedures Document for National Emission Inventory Criteria Air Pollutants, 1985-1999. https://www.epa.gov/sites/production/files/2015-07/documents/aerr_final_rule.pdf

Figure 3-2 compares the contribution of NO_x emissions from each NEI source group to the national total. As previously stated, industrial emissions account for 36% - 47% of the total (40% in 2018). However, Figure 3-2 clearly indicates that the largest national contributor of NO_x emissions originates from on-road vehicles and nonroad engines and vehicles. On-road vehicles include light-duty and heavy-duty gas and diesel vehicles. Nonroad engines and vehicles account for non-road gasoline and diesel engines, aircraft, marine vessels, railroads, and other sources. Similarly, Figure 3-3 compares the contribution of PM_{10} emissions across source groups. The discrepancy between group contributions is far more pronounced for this criteria pollutant where the "Miscellaneous" source group accounts for 78% to 90% of total PM_{10} emissions from 1990 – 2018 (82% in 2018). Conversely, industrial sources contribute only 9% - 14% of total emissions (11% in 2018).

Comparable trends are observed in Oregon emissions data as detailed in the next section. An important consideration for both datasets is to consider the resulting impact on visibility given the contribution of emissions to the national or state total. An enforced reduction to a minimally contributing factor (industrial source emissions) would intuitively result in a minimal effect on visibility in comparison to a reduction to the larger contributing factor (mobile/transportation sources and contributors to the miscellaneous source group).

Figure 3-2: National NO_x Emissions by Source Group

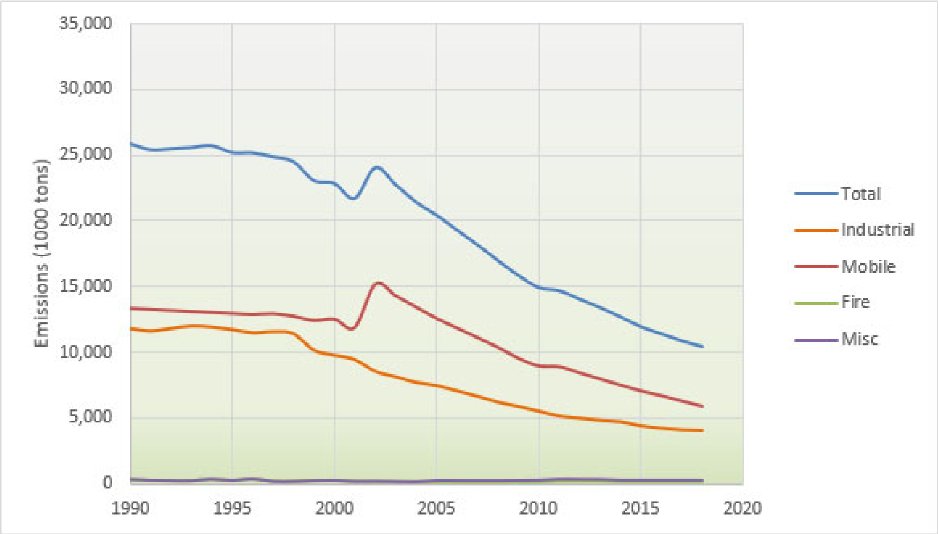
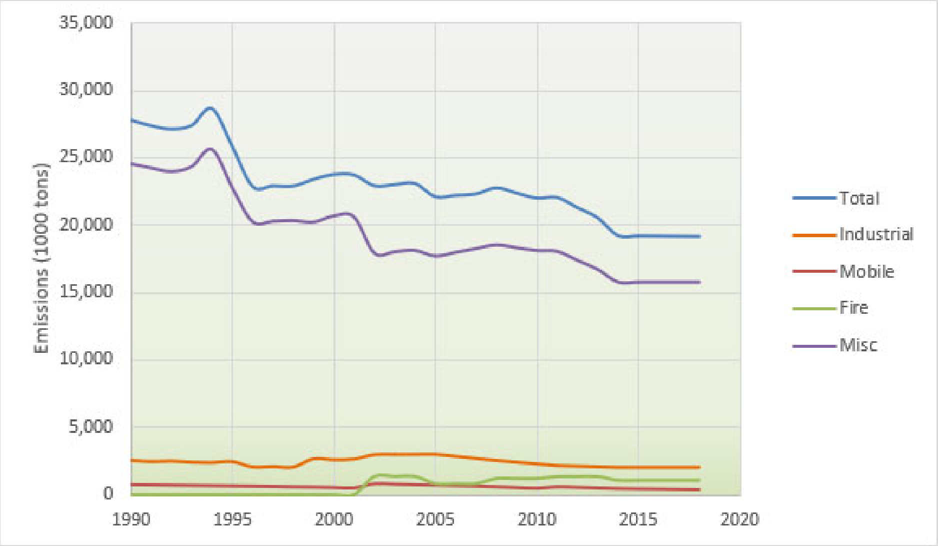


Figure 3-3: National PM_{10} Emissions by Source Group



3.2 Oregon Emissions

Also relevant to the discussion are the emissions trends of ODEQ's three primary compounds of concern in Oregon. As shown in Figure 3-4, there has also been a substantial reduction in industrial emissions within Oregon over the past 30-years.[7] Except for elevated PM_{10} emissions in 1999 and from 2002 – 2005, there has been a marked reduction in emissions of PM_{10}, NO_x, and SO_2 following a similar pattern to the national data. This demonstrates that Oregon has been contributing to achieving the national goal of the Regional Haze program.

Figure 3-5 provides historical emissions from all sources within Oregon. It also demonstrates an overall decrease in emissions of PM_{10}, NO_x, and SO_2. Historically, there has been more volatility in the trend of PM_{10} emissions, although the data still shows an overall decreasing trend. SO_2 and NO_x emissions are marked by less volatility and a more consistent decrease.

Figure 3-6 provides the industrial emissions data included in Figure 3-4 but in context to the scale of the y-axis in Figure 3-5. This demonstrates the contribution of industrial emissions to total state emissions.

---

[7] Oregon industrial emissions data obtained from the EPA National Emissions Inventory (NEI) State Emissions Trends database. https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data

Figure 3-4: Oregon Industrial Emission Trends of PM_{10}, SO_2 and NO_x (1990 – 2017)

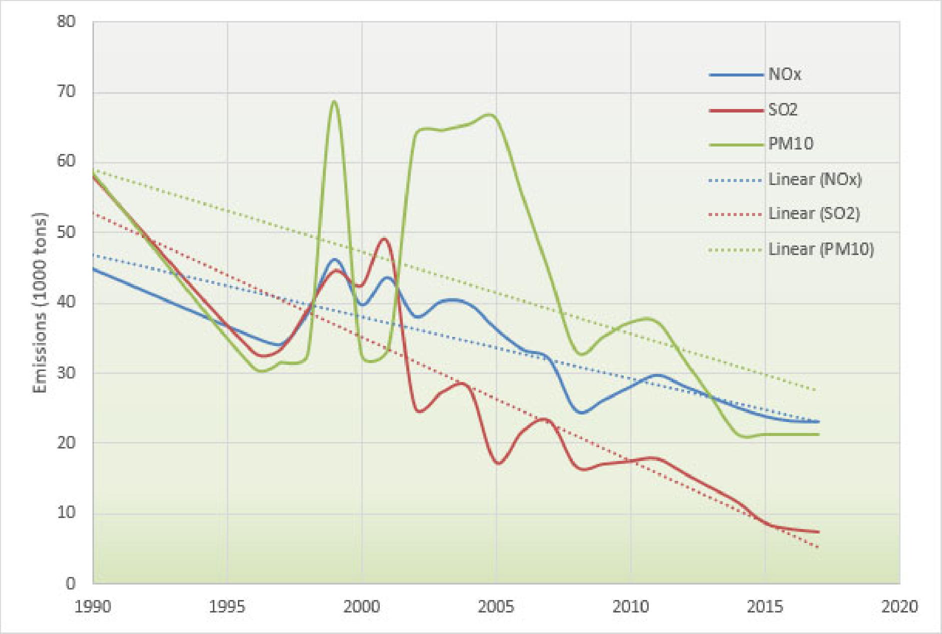


Figure 3-5: Oregon Total Emission Trends of PM_{10}, SO_2 and NO_x (1990 – 2017)

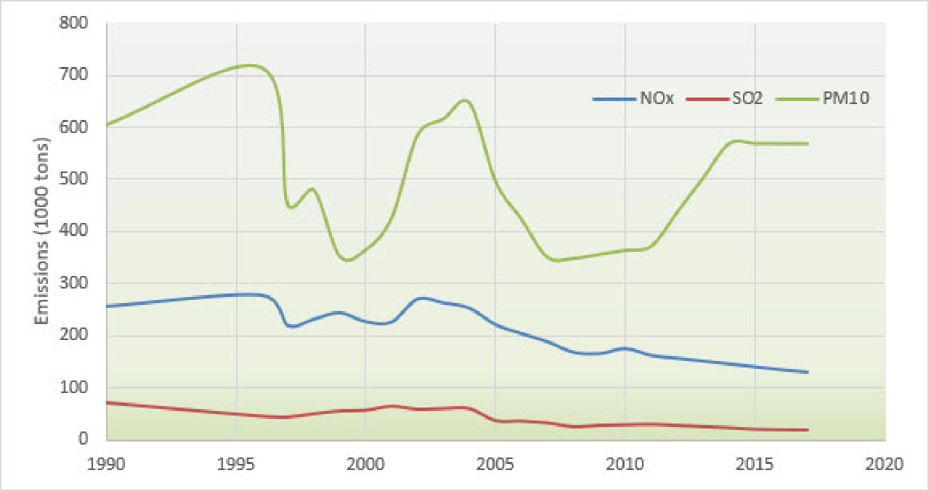
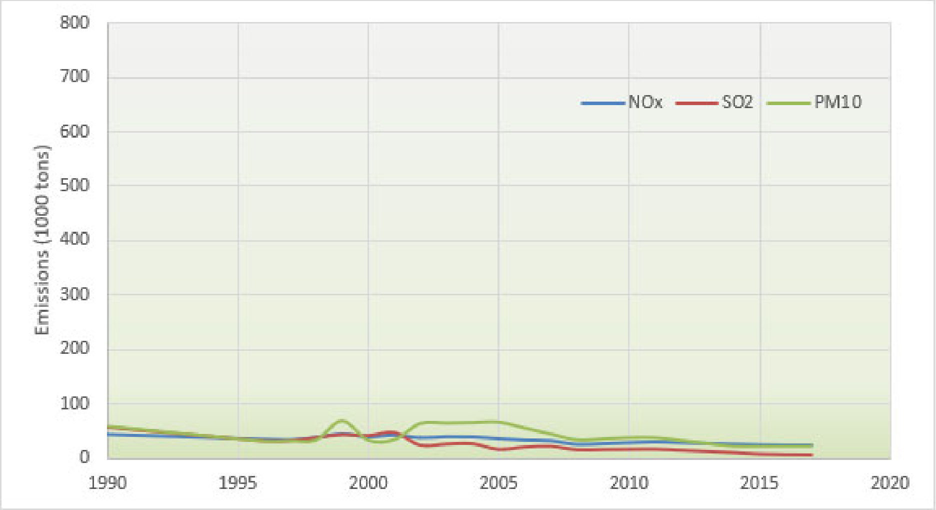


Figure 3-6: Oregon Industrial Emission Trends of PM_{10}, SO_2 and NO_x (1990 – 2017)



As shown in Figure 3-6, industrial emissions account for a minimal contribution to the overall total emissions in Oregon. In 2017, industrial emissions only accounted for 18%, 39%, and 4% of total state emissions of NO_x, SO_2, and PM_{10}, respectively. This is further evaluated by assessing the contributions of all source groups as conducted with the national emissions data.

Figure 3-7 compares the contribution of NO_x emissions from each NEI source group to the Oregon total. As previously stated, industrial emissions account for 13% - 19% of the total emissions. Figure 3-7 clearly indicates that the largest state-wide contributor of NO_x emissions originates from on-road vehicles and nonroad engines as seen nationally. These emissions account for 60% – 80% of total NO_x emissions within Oregon.

Similarly, Figure 3-8 compares the contribution of PM_{10} emissions across source groups to the state-wide total. Industrial sources again contribute minimally to total emissions (4% in 2017), whereas the “Miscellaneous” source group accounts for 48% to 95% of total PM_{10} emissions from 1990 – 2018 (82% in 2018). Additionally, wildfires and prescribed burn emissions have historically accounted for up to 39% of the total state-wide PM_{10} emissions. The Miscellaneous source group clearly mirrors the same trend as the total state-wide emissions and is clearly the largest contributor. However, Figure 3-8 also indicates that wildfires can provide substantial PM_{10} emissions to noticeably influence total emissions as shown from 2002 – 2004 and 2008 – 2017.

Figure 3-7: Oregon NO_x Emissions by Source Group

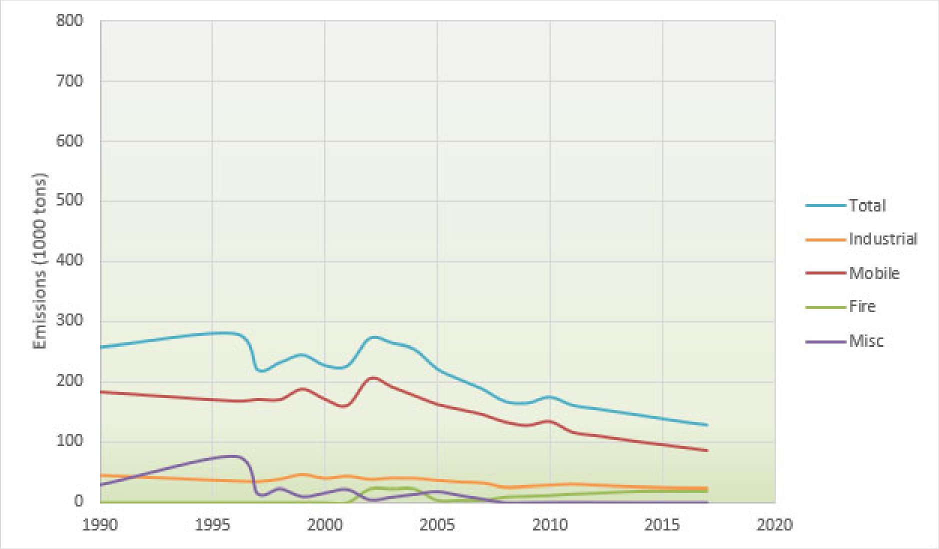
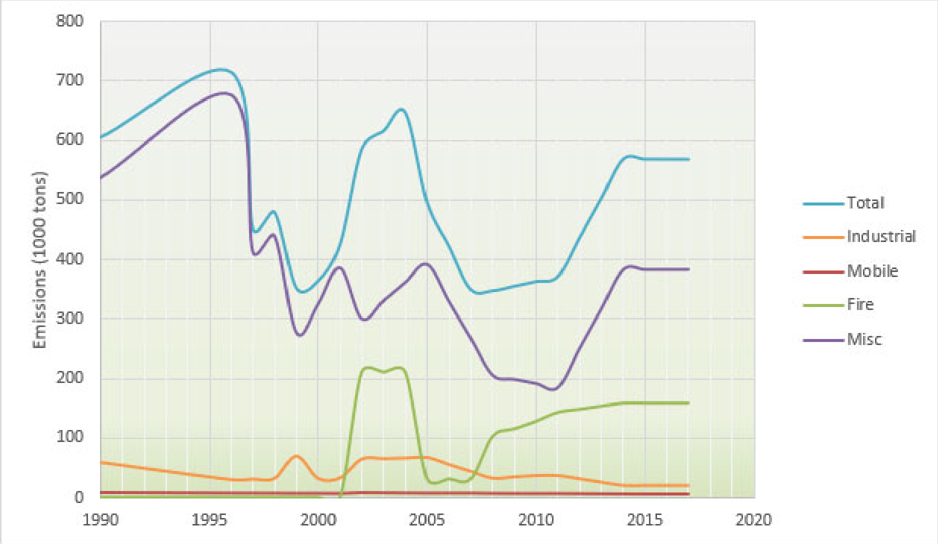


Figure 3-8: Oregon PM_{10} Emissions by Source Group



As discussed when evaluating national emissions, it's important to consider the resulting impact on visibility given the contribution of emissions to the state total. An enforced reduction to a minimally contributing factor (industrial source emissions) would intuitively result in a minimal to unnoticeable effect on visibility in comparison to a reduction to a larger contributing factor (mobile/transportation sources, wildfires, or contributors to the miscellaneous source group).

As stated on the ODEQ Air Quality website's home page, "about 90% of air pollution is generated from…everyday activities. Less than 10% is created from industry. Cars and trucks are the number one source of air pollution in Oregon."[8]

3.3 Interfor Gilchrist Emissions and Perspective

As the current four-factor analysis request arises from the RHR, it is important to understand the nature and purpose of the visibility protection program to ascertain important criteria that will lead to the selection of specific reasonable progress requirements. The RHR program (under ODEQ and EPA) has not previously considered Interfor's emissions as appropriate candidates for additional control under the reasonable progress (or any other) criteria.

Current emissions from the Interfor boilers are low and are not expected to increase during the foreseeable future. Based on the regulations and information reviewed, Interfor has concluded that the current baseline emissions of PM_{10}, SO_2 and NO_x are a reasonable estimate for the ongoing emissions from the facility.

3.4 Emissions vs Visibility Impairment Analysis

In order to consider the results of a four-factor analysis as described by the RHR, there must be first and foremost a reasonable probability of an actual improvement in visibility impairment from emissions reductions from the Interfor facility, particularly the hog fuel boilers. This analysis relies on actual visibility data - IMPROVE data - collected at Crater Lake National Park, which is considered representative of visibility conditions in the Diamond Peak Wilderness.

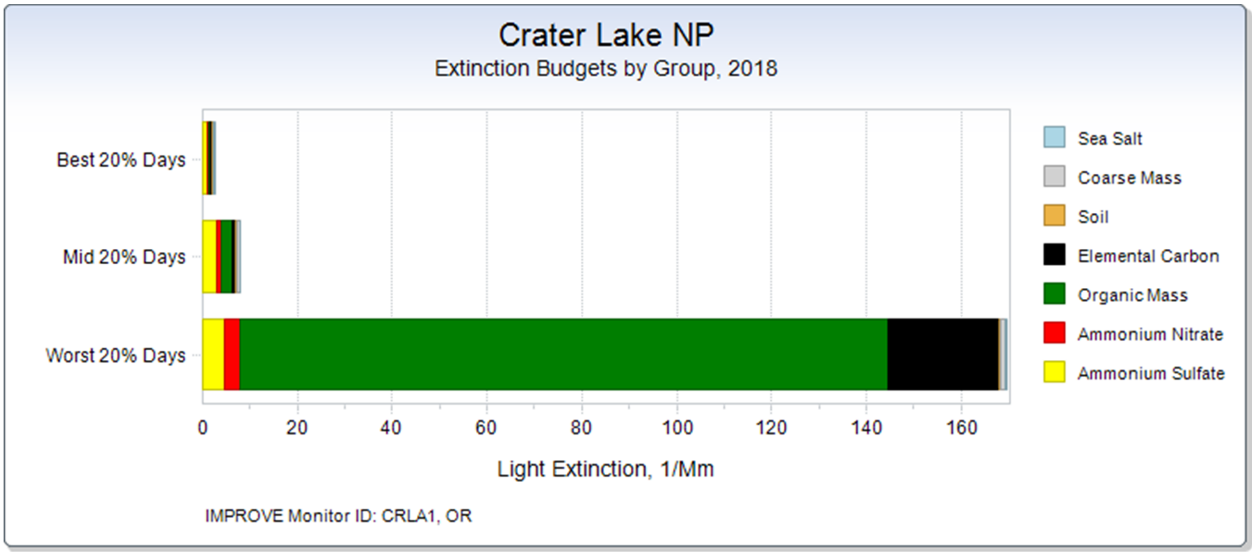
As was shown in Figure 2-1, IMPROVE monitoring shows that the primary pollutants that account for the most anthropogenic (human-caused) visibility degradation are ammonium sulfate and ammonium nitrate [2]. The primary pollutant that accounts for the most non-anthropogenic visibility degradation is organic carbon matter. Wildfire smoke is the major source of organic carbon matter in the air.

Figure 3-9 shows the contribution of each compound to light extinction (which is the parameter that accounts for visibility impairment) at Crater Lake National Park on the 20% best visibility days, 20% mid-range visibility days and 20% worst visibility days [6]. This data figure clearly shows that organic mass is by far the largest contributor to visibility impairment at the Class I area.

---

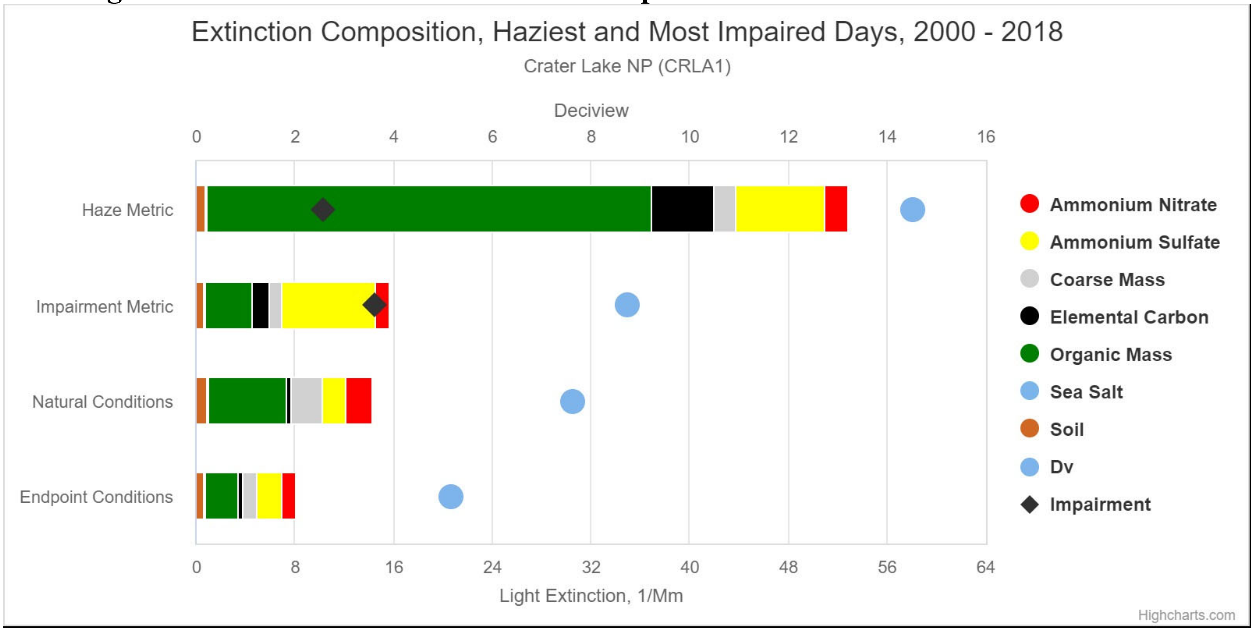
[8] "Sources of air pollution" https://www.oregon.gov/deq/aq/pages/default.aspx

Figure 3-9: IMPROVE Visibility Data for Crater Lake National Park



Additionally, Figure 3-10 provides the composition of visibility imparing pollution by deciview for each metric. Clearly, organic mass dominates the haze metric while ammonium sulfate provides the majority of the impairment metric. As stated previously, visibility degradation caused by anthropogenic (human-based) sources is defined as “impairment”. Interfor Gilchrist is not a large emitter of NO_x or SO_2, which are the precursors to ammonium sulfate formation.

Figure 3-10: IMPROVE Extinction Composition for Crater Lake National Park



4.0 INTERFOR GILCHRIST EMISSIONS INFORMATION

4.1 Equipment Description

The Interfor Gilchrist facility includes a sawmill, drying kilns, a planer mill, and associated equipment used to process raw logs into dried lumber. A steam plant provides steam to heat the dry kilns for lumber drying. The steam plant and lumber kilns generally operate continuously with varying steam demand. The sawmill, planing, and material handling facilities typically operate one or two shifts per week, 52 weeks per year.

Point sources of emissions at the facility include wood-handling cyclones, the lumber dry kilns, and the boilers in the steam plant. The steam plant sources include emission units B-1, B-2 and B-3, all of which are sources of NO_x, SO_2, VOC and PM_{10} emissions. Emission units B-1 and B-2 are Dutch oven boilers that were manufactured by Wickes in 1939. Each of these boilers has a steam production capacity of approximately 50,000 pounds per hour (lb/hr) steam. Steam from the two boilers is measured by a single steam flow monitor. B-1 and B-2 are each equipped with a multiclone to control PM emissions and both boilers exhaust through a common stack. A multiclone is type of mechanical separator that contains an array of cyclones used to clean the boiler exhaust.

Emission unit B-3 is a dual-fuel Murray Iron Works natural gas-fired water tube boiler manufactured in 1972 that was refurbished and installed at the Gilchrist facility in 1999. This boiler also has the capacity to burn distillate oil as a back-up fuel in case of natural gas curtailment. Boiler B-3 has not been fired on oil at the Gilchrist site and is rarely used for steam production. Two small Cleaver Brooks natural gas boilers, emission units B-4 and B-5, are used seasonally for building heat.

The Gilchrist facility also includes three double-track and four single-track steam-heated lumber dry kilns that were installed between 1999 and 2007. Three material handling cyclones were installed in 1974: two hog fuel cyclones and a planer shavings cyclone. These cyclones transport material and control PM emissions generated during material handling. Other emission-generating material handling operations include conveyors for hog fuel, sawdust, chips, and shavings, a small debarker, a large debarker, and two sawmill building vents.

4.2 Emissions Units and Emissions Inventory

Significant emission units at the Interfor Gilchrist facility and their associated control devices are listed in Table 4-1. The list is based on Section 3 of Permit Number 18-0005.

Table 4-1: Significant and Insignificant Emission Units

Source	EU ID	Description	Control Equipment
Steam Plant	B-1	Wood/Bark-Fired Boiler	Multiclone #1
	B-2		Multiclone #2
	B-3	Natural Gas/Oil-Fired Boiler	None
Building Heat	B-4	Natural Gas/Oil-Fired Boiler	None
	B-5		
Kilns	Kilns	Wood Drying Kilns	None
Material Handling	Cyclones	Hog Fuel Cyclones Planer Shavings Cyclone	None
	Conveyors	Material Handling hog fuel, sawdust, chips, shavings	
Sawing and Debarking	S&D	Log Sawmills: Sawing and Debarking	None
Unpaved Roads	UPR	Unpaved Roads	Watering
Aggregate Insignificant	AI	CO, VOCs, PM/PM_{10} emissions from Cleaver Brooks Boilers and filing room cyclone	None

4.3 Emission Inventory

The plant site emission limits (PSELs) for the Interfor Gilchrist facility are summarized in Table 4-2. PSELs are the highest allowable potential emissions from sources at the facility and are always greater than actual emissions. The PSELs are listed in the review report for the Interfor Gilchrist Air Operating Permit.

As stated in Section 1.4, the initial Q/d analysis used to trigger the four-factor analysis requirement was based on the emissions for the entire facility; however, the four-factor analysis is focused on individual emission sources. The largest sources of SO_2, NO_x and PM_{10} emissions at the facility are the hog-fuel boilers, B-1 and B-2. The dry kilns are a significant source of VOC emissions, but VOC emissions are not part of the visibility analysis. The three material handling cyclones account for around 6% of the PM_{10} PSEL, and each cyclone discharges from a sperate point. The cyclones operate at ambient temperature and the emissions plumes are not widely dispersed.

Table 4-2: Interfor-Gilchrist PSEL

Emissions Unit		PM	PM_{10}	$PM_{2.5}$	SO_2	NO_x	VOC	CO
		T/yr	T/yr	T/yr	T/yr	T/yr	T/yr	T/yr
Steam Plant	B-1	204	187	115	5.3	97.2	14.1	706
	B-2							
	B-3 NG	0.38	0.285	0.29	0.13	5	0.275	4.2
	B-3 Oil	0.2	0.2	0.14	1.42	2	0.025	0.5
Building Heat	B-4 NG	0.0375	0.0375	0.04	0.039	1.5	-	-
	B-5 NG							
	B-4 Oil	0.0025	0.0025	0	0.0142	0.02	-	-
	B-5 Oil							
Kiln (All Species)	Kilns	2.3	2.3	1.61	-	-	194.4	-
Cyclones (A,B,C)	Cyclones	21	11.6	5.75	-	-	-	-
Material Handling	Conveyors	9.5	3.8	1.89	-	-	-	-
	Shavings							
Sawing and Debarking	S&D	2.3	1.4	0.68	-	-	-	-
Building Vents	Vents	0.4	0.4	0.21	-	-	-	-
Unpaved Roads	UPR	1	0.3	0.03	-	-	-	-
Totals		**243**	**208**	**126**	**39**	**104**	**209**	**721**

4.3.1 Emission Sources Selected for Four-Factor Analysis

The Wickes hog fuel boilers, B-1 and B-2, were selected as the only sources to be evaluated by four-factor analysis because they are the largest emitters of NO_x, SO_2, and PM_{10} at the facility. B-1 and B-2 produce 97.4% of the actual PM_{10} emissions and 99.7% of the actual NO_x emissions from the facility. The two boilers exhaust from a tall stack with high exhaust temperature, resulting in high plume momentum and wide plume dispersion.

The hog-fuel boilers produce trace amounts of SO_2 from naturally occurring sulfur in the wood and bark. If boiler B-3 were fired on fuel oil, it could also be a source of SO_2 emissions. Interfor does not use the fuel oil option in B-3 even though fuel oil use in B-3 is allowed in the permit.

4.3.2 Lumber Dry Kiln Exclusion

Lumber dry kilns emit VOC and PM_{10} from the press vents; they do not emit NO_x or SO_2. VOC emissions are not included in the visibility impairment calculations. Kiln exhaust vents are roughly as high as a single-story building and have high moisture content and low temperature. The resulting emissions plume contains primarily steam and has poor dispersion characteristics. Controlling emissions from lumber kilns vents is challenging and is rarely achieved.

4.3.3 Material Handling Cyclones and Minor Source Exclusions

The emissions sources at the Interfor Gilchrist facility include three cyclones used in transporting wood residuals. The cyclones exhaust at ambient temperature and only emit wood particulate matter that has been mechanically generated by grinding, chipping or planing wood material. Cyclone exhaust has low concentrations of PM emissions and poor plume dispersion characteristics, resulting in little potential for impacting visibility at any Class I area.

The other PM emission sources at the facility have the potential to generate fugitive PM_{10} emissions. The facility Title V air operating permit requires that Interfor monitor fugitive emissions and take corrective action of fugitive emissions are observed leaving the property boundaries. Therefore, none of the fugitive emission sources have been included in the 4-factor analysis.

5.0 FOUR-FACTOR ANALYSIS FOR HOG-FUEL BOILER PM_{10}

Evaluation of available control technologies requires an analysis of the cost effectiveness of the emissions control application. Cost effectiveness relies on a comparison of the current PM_{10} emissions and the controlled PM_{10} emissions. The current actual emissions are the emissions as controlled by the multiclones, as discussed below. Steam from B1 and B2 is measured together using a single steam flow monitor.

Particulate Matter (PM) emissions from the boilers are subject to the Oregon State grain loading standard of 0.15 grains per dry standard cubic feet (gr/dscf) at 12% oxygen, based on Oregon Administrative Rule (OAR) 340-226-0210. The boilers are currently meeting the emission limit using the multiclones. PM_{10} emissions consist of filterable particulate matter and condensable particulate matter. Filterable particulate matter can be reduced using the control technologies described in this section. However, condensable particulate matter remains in gaseous phase and is not affected by the control equipment.

5.1 Available PM_{10} Control Technologies

A variety of particulate control technologies are available for removing particulate from the wood-fired boiler exhaust. The following control technologies have been considered in this four-factor analysis.

- mechanical collectors (cyclone or multiclones)
- wet venturi scrubber
- fabric filter baghouse
- electrostatic precipitator (ESP)

5.1.1 Mechanical Collectors

Wet scrubbers, baghouses and ESPs are most frequently installed downstream of a mechanical collector system. The mechanical collector removes the bulk of the large particulate and reduces the loading on the secondary control equipment. Boilers B-1 and B-2 are each equipped with multiclones to reduce PM_{10} emissions. A multiclone is an array of cyclones used to mechanically separate particulate matter emissions from the boiler flue gas. The multiclones remove cinders and entrained fuel particles as well as the much smaller PM_{10} emissions.

This analysis evaluates the cost and feasibility of installing additional PM_{10} emissions control technologies downstream of the multiclones to improve the collection efficiency. The multiclones would not be removed or replaced.

5.1.2 Venturi Wet Scrubbers

Wet scrubbers use water for removing particulates from the boiler exhaust gas. Venturi scrubbers are a type of wet scrubber that accelerates the flow of gas and water through a constriction, forcing the water to come in contact with the gas stream. For the Interfor wood-fired boilers, use of a venturi scrubber would require an increase in the flue gas pressure drop, which would require an increase in fan size and electrical power consumption.

The key drawback of venturi wet scrubbers is that the consume water and generate a waste sludge that must be disposed [7]. Water consumption and waste sludge generation are negative environmental impacts not associated with the use of dry particulate control systems. Wet scrubbers haver lower collection efficiencies than other particulate control technologies that are available. For these reasons, wet scrubbers, including venturi scrubbers, are not considered further in this four-factor analysis.

5.1.3 Fabric Filter Baghouses

Fabric filter baghouses are not commonly installed on wood-fired boilers because of the fire risk. The filter bags can become caked with a layer of wood ash containing unburned carbon. If a spark escaped the multi-cyclones, it could very easily start a fire in the baghouse. Use of a baghouse on a wood-fired boiler would require use of an abort stack to be triggered whenever a spark was detected or the spark detector equipment was being cleaned. Because of the fire risk and the need for a baghouse bypass system, use of a fabric filter baghouse will not be considered further for this analysis.

5.1.4 Electrostatic Precipitator

Electrostatic precipitators (ESPs) are commonly used as a secondary particulate control technology for wood-fired boilers. Dry ESPs are most common and do not create a contaminated water stream. They are much less susceptible to fire than fabric filter baghouses.

ESPs control emissions of particulate matter by charging the particles as they pass through an electric corona discharge ionization zone. The charged (ionized) particulates are attracted to grounded collection plates that are maintained in an electric field. The particulates collect on the plates and are thus removed from the gas stream. Particulates are removed from the plates by periodic rapping into a hopper.

ESPs are commonly and effectively used in the industry and have fewer adverse environmental impacts compared to wet scrubbers. This is reflected in recently permitted biomass-fired boilers at similar facilities, which were required to be equipped with ESPs to control filterable PM emissions (RBLC IDs SC-0149, ME-0040 and FL-0361).

5.1.5 Summary of PM_{10} Control Technologies

The Interfor hog fuel-fired boilers are currently equipped with multiclones and must comply with the grain loading limit of 0.15 gr/dscf in accordance with OAR 340-226-0210. The analysis has identified an ESP as the only feasible add-on PM_{10} control technology that would be most likely to show a positive outcome for each of the four factors.

The following four-factor analysis reviews the economic, energy, and environmental impacts of installing an ESP on each boiler, as well as the schedule of installation and duration of impact. An ESP could potentially reduce PM_{10} emissions from each boiler by

84%. Higher efficiency can be achieved for the filterable portion of the PM_{10} emissions, but the condensable portion is unaffected by the control equipment.

5.2 Current Actual PM_{10} Emissions and Post-Control PM_{10} Emissions

The initial Q/d analysis used to trigger the four-factor analysis requirement was based on both the reported actual emissions and the PSEL for the entire facility. However the four-factor analysis itself is focused on individual emission sources. The largest sources of PM_{10} emissions are the hog fuel boilers, B-1 and B-2 which produce 97.4% of the actual PM_{10} emissions from the Interfor facility. Therefore, this analysis will only review control technologies for PM_{10} emissions from B1 and B2, since controlling emissions from the other emissions sources is unlikely to be cost effective or offer substantial benefit.

The Oregon annual air contaminant emissions reports rely on an emission factor provided in the Interfor air quality permit of 0.5 pounds per thousand pounds of steam (lb/klb). Interfor has reviewed source test results and found that this emission factor is well-representative of actual emissions from the boilers. For setting the baseline for this analysis, the average boiler steam production rate for reporting years 2016 and 2017 was used. Steam produced by B1 and B2 is measured on a single steam flow monitor. The combined average boiler steam production rate was 455,750 klb/yr and 227,875 klb/yr was assigned to each boiler. Baseline PM_{10} emissions are estimated as follows:

0.5 lb/klb * 227,875 klb/yr ÷ 2000 lb/ton = 57.0 tpy per boiler

The emission factor of 0.5 lb/klb steam can also be expressed in units of pounds per million Btu (lb/MMBtu) based on the accepted heat input to steam output conversion of 1.588 MMBtu heat input to 1000 lb steam output (1.588 MMBtu/klb). The current boiler emission factor is equivalent to:

0.5 lb/klb ÷ 1.588 MMBtu/klb = 0.315 lb/MMBtu heat input

Review of 3 BACT determinations for similar wood-fired boilers contained in the EPA RBLC database, shows permitted PM_{10} emission rates with ESPs of 0.05 lb/MMBtu, including filterable and condensable PM_{10}.

For this analysis, Interfor has assumed a final ESP PM_{10} emission rate of 0.05 lb/MMBtu, which represents a reduction of 84% from the current emission rate. The emission factor can be used to calculate controlled annual emissions as follows:

0.05 lb/MMBtu * 1.588 MMBtu/klb = 0.08 lb/klb
0.08 lb/klb* 227,875 klb/yr = 9.1 tpy per boiler

5.3 Factor 1: Cost of Compliance

A cost estimate for installation of an ESP on one of the hog fuel boilers has been developed. The ESP vendor that Interfor contacted recommended a separate ESP on each boiler so the boilers could be operated independently if needed. The cost estimate was generated based on the cost estimation procedure in Section 6, Chapter 3 of EPA's

Control Cost Manual [8]. A print-out of a spreadsheet with the cost estimation procedure and calculations, including footnotes and the final calculated cost effectiveness of an ESP, is presented in Appendix B.

5.3.1 ESP Data Inputs

ESPs are designed based on the volumetric flow of gas, the temperature of the gas stream, type of particulate, and the particulate inlet load and outlet load. These parameters are then used to estimate ESP cost using the “Full SCA Procedure” [8]. The SCA, the specific collection area, is the ratio of the collection plate area, A, divided by the gas volumetric flow rate, Q, and has English units of $ft^2/ft^3/s$, which simplifies rather unintuitively to s/ft. The SCA and the volumetric flow rate of the exhaust gas are then used to calculate the square footage of the plate area. Figure 3.5 in the Control Cost Manual provides a cost estimate, from flange-to-flange, of the ESP based on the plate area. The following summarizes the data used in the Full SCA Procedure.

The Control Cost Manual describes five different types of ESPs. Interfor has contacted an ESP vendor who recommended a flat plate precipitator. According to the Control Cost Manual, flat plate precipitators represent a “significant number of smaller precipitators (100,000 to 200,000 acfm)”. Each of the boilers can exhaust up to 80,400 actual cubic feet per minute (ACFM) based on theoretical combustion calculations and supported by the results of the Interfor stack tests. The Full SCA Procedure was done for a flat plate style precipitator for a single boiler, which is what is presented in this analysis.

The operating temperature was estimated at 500°F based on stack tests from 2012, 2016, and 2017. No severe back corona was assumed based on the description of the causes of back corona in the Control Cost Manual. The mass median diameter of the inlet particle distribution, MMDi, is 5 µm for wood burning boilers as indicated in Table 3.5. Sneakage was set at 0.10 based on Table 3.6 for flat plate precipitators and rapping reentrainment was estimated at 0.14 from Table 3.7 based on the “not known” value.

The rapping puff size parameter, MMDr, was estimated to be 4 µm, since a value of 3 µm[9] was given for an MMDi < 5 µm, and a value of 5 µm was given for an MMDi > 5 µm (the MMDi for wood-fired boilers is exactly 5 µm).

The average electric field, E_{avg}, for flat plate ESPs was calculated using equation 3.33 for average field, no back corona, and positive polarity.

The number of ESP sections, n, was determined to be 2, consistent with Table 3.8 given that the 84.0% efficiency is less than 96.5%.

The other parameters were calculated according to the Full SCA Procedure as outline in the Control Cost Manual [8]. The SCA of each section was calculated and then added

---

[9] The Control Cost Manual lists the MMDr as having units of meters; however, it seems that must be a typo. It was assumed that the units of MMDr are micrometers.

together to get the total SCA in metric units. This was converted to English units to get the English SCA, ESCA, in units of square feet per thousand actual cubic feet of gas (ft^2/kacfm), which was then multiplied by the estimated design boiler exhaust flow rate of 80.4 kacfm to get the square footage of plate area. The plate area was calculated to be 29,253 ft^2.

Figure 3.5 in the Control Cost Manual is a graph of dry-type ESP flange-to-flange purchase price vs. plate area [8]. Using the equation for the upper curve for rigid electrode design with all standard options (such as inlet and outlet nozzles, diffuser plates, hopper options, stair access, structural supports, and insulation) and an estimated plate area of 29,253 ft^2, the estimated cost of the ESP is $566,105 in 1987 dollars.

Using the United States (U.S.) Bureau of Labor Statistics Producer Price Index (PPI) for Series ID PCU33341333341311 “Dust collection and other air purification equipment for industrial gas cleaning systems” (based on NAICS code 333413, Fan, blower, air purification equipment manufacturing), an adjustment ratio was calculated to convert the ESP cost estimate from 1987 dollars to January 2020 dollars. The base year for this index is 1983, which is assigned the value of 100. Data for the index was not recorded until the middle of 1989, and the first full year of data with an annual average value for the index is 1990. Therefore, linear interpolation was used to estimate the annual average index value for 1987 using a value of 100 in 1983 and the annual average of 114.4 in 1990 to obtain an estimated index value of 108.2 for 1987. The PPI for this category was 206.8 in January 2020. Thus the cost estimate of $566,105 was adjusted by multiplying by 206.8/108.2 to obtain an ESP cost estimate of $1,081,698 in 2020 dollars.

Estimated total annual costs for ESP installation and operation were calculated according to the Control Cost Manual [8]. Direct and indirect costs of ESP installation were estimated according to Table 3.16 to calculate a Total Capital Investment (TCI) of $2,884,144 in 2020 dollars. Applying a retrofit factor of 1.4, representing an average relative difficulty, results in an adjusted TCI of $4,037,801 for one ESP installed on one of the hog fuel boilers. This includes a necessary electrical upgrade at the Gilchrist facility to supply the type of electricity necessary to operate an ESP.

Direct and indirect annual costs were then calculated per Control Cost Manual [8] guidance. The references for the wage values and cost of electricity are noted in the calculation spreadsheet and included in Appendix C. The TCI was broken down into a Capital Recovery Cost over the assumed twenty years of equipment life and based on the recent Prime Rate of 3.25% (Note 15 of the ESP spreadsheet). Total annual direct operations and maintenance (O&M) costs and indirect costs for capital recovery, taxes, insurance, and overhead are calculated at $597,411/yr.

5.3.2 Cost Effectiveness Calculation Results

The tons per year of PM_{10} removed were calculated based on the actual tons of PM_{10} emitted from one of the hog fuel-fired boilers of 57.0 tpy and a controlled emission rate of 9.1 tpy based on the same steam production pattern. This results in a reduction of 47.9

tons/yr of PM_{10} per boiler. Cost per ton removed is calculated by dividing the total annual cost by the tons of PM_{10} removed, as shown below:

$597,411/yr ÷ 47.9 tons/yr = $12,484 per ton of PM_{10} removed.

The PM_{10} emissions control cost calculations are summarized in Table 4-1.

Table 5-1: Wood Fired Boiler Cost Effectiveness Analysis – PM_{10}

Control Technology	% Reduction	Emissions (tons/year)	Emissions Reduction (tons/year)
Existing Multiclones	Base Case	57.0 each 114 tpy combined	Base Case
Venturi Wet Scrubber	Not feasible due to water usage and contamination.		
Fabric Filter Baghouse	Not feasible due to fire danger.		
Electrostatic Precipitator	84.0%	9.1 tpy each 18.2 tpy combined	47.9 tpy each 95.8 tpy combined
ESP Cost Parameters			
Boiler Steam Production Capacity	50,000 pounds of steam per hour each 100,000 pounds of steam per hour combined		
Boiler Heat Input Rate	79.4 million Btu per hour each 158.8 million Btu per hour combined		
Estimated ESP Direct and Indirect Capital and Installation Costs	$4.04 million, each $8.08 Million, combined		
Total indirect annual costs, including capital recovery	$492,100 each $984,200 combined		
Total direct annual O&M Costs	$105,300 each $210,600 combined		
Total Annual Capital Recovery and O&M Costs	$597,400/yr each $1,194,800 combined		
Cost per ton PM_{10} Removed	$597,400 ÷ 47.9 tpy = $12,500/ton $1,194,800 ÷ 95.8 tpy = $12,500/ton		

5.4 Factor 2: Time Necessary for Compliance

Interfor estimates that it would take approximately 24 to 30 months to obtain ESP bids, review, award the contract, then design, permit, finance, install and commission an ESP on each of the hog fuel boilers.

5.5 Factor 3: Energy and Environmental Impacts of Compliance

Installing ESPs on boilers B-1 and B-2 would increase the facility's energy consumption, which would have a negative environmental impact at the point of power generation in the form of air pollution, including greenhouse gases.

5.6 Factor 4: Remaining Useful Life

For this analysis, it was assumed that boilers B-1 and B-2 have a remaining useful life of 20 years based on ODEQ guidance that a 20-year planning horizon should be assumed unless a unit is scheduled for shutdown sooner. Interfor has a systematic repair and maintenance program for the boilers and intends to keep the boiler operating for many years.

6.0 FOUR-FACTOR ANALYSES FOR SO_2 AND NO_X

The following sections present the analysis for the Interfor Gilchrist facility using primarily the direction of the EPA Draft Guidance [9] and the WRAP 2009 four-factor analysis [10]. The initial step in the four-factor analysis was to identify possible additional control options for this source. As discussed above, the four-factor analysis focused on controls for each of the Interfor hog fuel-fired boilers, B-1 and B-2.

6.1 Available SO_2 Control Technologies

SO_2 is formed during combustion due to the oxidation of sulfur in the fuel. Woody biomass fuel is naturally low in sulfur and SO_2 emission controls are typically not used on wood-fired boilers.

The Oregon annual air contaminant emissions reports rely on an SO_2 emission factor provided in the Interfor air quality permit for boilers B-1 and B-2 of 0.01 lb/klb. The current actual emissions are calculated based on the average boiler steam production rate for reporting years 2016 and 2017. Steam for B1 and B2 is measured on a single steam flow monitor. The combined average boiler steam production rate was 455,750 klb/yr and current actual SO_2 emissions are estimated as follows:

0.01 lb/klb * 455,750 klb/yr ÷ 2000 lb/ton = 2.3 tpy

Any add-on control to further reduce SO_2 emissions would be cost-prohibitive due to the small amount of pollutant controlled.

6.2 Available NO_x Control Technologies

NO_x is formed during the combustion of woody biomass in the two hog fuel boilers. NO_x comes from two sources in combustion, fuel NO_x and thermal NO_x. Fuel NO_x forms due to oxidation of nitrogen contained in the biomass fuel and thermal NO_x forms from the thermal fixation of atmospheric nitrogen and oxygen in the combustion air. NO_x emissions from a boiler can be controlled using combustion modifications that reduce thermal NO_x formation, or by add-on control devices to remove NO_x from the exhaust stream after it is formed. Combinations of combustion controls and add-on controls may also be used to reduce NO_x. This analysis will consider the following NO_x control technologies:

- combustion modification
- selective catalytic reduction (SCR)
- non-selective catalytic reduction (SNCR)

6.2.1 Combustion Modification

The two hog fuel boilers are Dutch-oven style boilers constructed in 1939. As such, the boilers' design and operation are not well suited to combustion controls. Combustion controls, such as flue gas recirculation, staged combustion, low NO_X burners, and fuel staging are either not compatible with Dutch oven boilers or do not have high NO_X control rates. Hog fuel also contains some fuel-bound nitrogen that readily converts to NO_X, which is not reduced by combustion controls. This fuel NO_X further reduces the assumed NO_X control of the various combustion modifications.

6.2.2 Selective Catalytic Reduction

SCR is a post-combustion gas treatment technique for reduction of nitric oxide (NO) and nitrogen dioxide (NO_2) to molecular nitrogen, water, and oxygen. Ammonia (NH_3) or urea is used as the reducing agent and is injected into the flue gas upstream of a catalyst bed. Urea is converted to ammonia after injection into the hot flue gas. NO_x and NH_3 combine at the catalyst surface, forming an ammonium salt intermediate which subsequently decomposes to elemental nitrogen and water. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. Technical factors that impact the effectiveness of SCR include inlet NO_x concentrations, catalyst reactor design, operating temperatures and stability, type of fuel fired, sulfur content of the fuel, design of the ammonia injection system, catalyst age and reactivity, and the potential for catalyst poisoning [11].

SCR control technology works best for flue gas temperatures between 575°F and 750°F and is typically installed upstream of the particulate control equipment where the temperature is high enough to support the process. When the combustion source is a biomass-fired boiler, the SCR must be placed downstream of the particulate control equipment for proper operation, since the PM in the flue gas would foul the SCR catalyst. At this point in the exhaust system, the flue gas temperature is lower than required for the SCR to operate effectively. Source tests of the hog fuel boilers' combined stack show an average stack exit temperature of approximately 500°F.

SCR has not been required on small- and medium-sized biomass-fired boilers according to a search of the most recent ten-year period in EPA's RACT/BACT/LAER Clearinghouse (RBLC). For the reasons stated in this section, Interfor considers this alternative technically infeasible, and SCR is eliminated from any further consideration as a feasible control technology.

6.2.3 Selective Non-catalytic Reduction

SNCR drives the noncatalytic decomposition of NO_x in the combustion gases to nitrogen and water using a reducing agent (e.g., ammonia or urea). The reactions take place at much higher temperatures than in an SCR, typically between 1,650°F and 1,800°F, because a catalyst is not used to drive the reaction. The SNCR reaction can take place upstream of the particulate control equipment and supplemental fuel is not required. The efficiency of the conversion process diminishes quickly when operated outside the optimum temperature band and additional ammonia slip or excess NO_x emissions may result [12].

Removal efficiencies of NO_x vary for SNCR, depending on inlet NO_x concentrations, fluctuating flue gas temperatures, residence time, amount, and type of nitrogenous reducing agent, mixing effectiveness, acceptable levels of ammonia slip, and the presence of interfering chemical substances in the gas stream. The estimated control efficiency for SNCR retrofitted onto an existing wood-fired boiler is 30%-50%.

SNCR technology is a feasible emissions control for wood-fired boilers and will be evaluated in this four-factor analysis. This is reflected in a recently permitted biomass-fired boiler of similar size that was equipped with SNCR to meet the BACT control requirements (RBLC ID SC-0149). The following four-factor analysis examines the environmental, energy and economic impacts of an SNCR installation on the hog fuel boilers.

6.2.4 Selective Non-catalytic Reduction

The initial Q/d analysis used to trigger the four-factor analysis requirement was based on the reported actual emissions for the entire facility, but the four-factor analysis is focused on individual emission sources. The largest sources of NO_x emissions are the hog fuel boilers, B-1 and B-2 which produce 99.7% of the actual NO_x emissions from the Interfor facility. Therefore, this analysis will only review control technologies for NO_x emissions from B1 and B2, since controlling emissions from the other emissions sources is unlikely to be cost effective or offer substantial benefit.

6.3 Current Actual NO_x Emissions and Post-control NO_x Emissions

The hog fuel-fired boilers are not currently equipped with any NO_x control, nor are there any permit limits on NO_x emissions from the two boilers. The Oregon annual air contaminant emissions are reported based on an emission factor provided in the permit of 0.26 lb/klb. For setting the baseline for this analysis, the average boiler steam production rate for reporting years 2016 and 2017 was used. Steam for B1 and B2 is measured on a single steam flow monitor and the combined average boiler steam production rate was 455,750 klb/yr and 222,875 klb/yr was assigned to each boiler. Baseline NO_x emissions are estimated as follows:

0.26 lb/klb * 227,875 klb/yr ÷ 2000 lb/ton = 29.6 tpy each

The emission factor of 0.26 lb/klb steam can also be expressed in units of lb/MMBtu based on the accepted heat input to steam output conversion of 1.588 MMBtu heat input to 1000 lb steam output. The current boiler emission factor is:

0.26 lb/klb ÷ 1.588 MMBtu/klb = 0.164 lb/MMBtu heat input

Equation 1.17 in the EPA Control Cost Manual for SNCR [12] is a means for estimating the Normalized Stoichiometric Ratio (NSR). The NSR defines the amount of reducing reagent (ammonia or urea) needed to achieve a targeted NO_x reduction; since more than the theoretical stochiometric amount of ammonia or urea is required to reduce a given amount of NO_x, the NSR ranges between 0.5 and 3. Figure 1.7 in the Control Cost Manual shows the effect of the NSR on NO_x reduction. Just above the figure, the Manual states, “Increasing the quantity of reagent does not significantly increase the NO_x reduction for

NSR values over 2.0." Additionally, increasing the amount of reducing reagent added to the system results in increasing amounts of ammonia slip.

Based on Equation 1.17 and an upper bound of 2.0 for NSR, the estimated achievable NO_x reduction in the Steam Plant boilers is 32%. This estimated NO_x reduction is reasonable, and possibly even optimistic, given the relatively low inlet NO_x emissions from the boilers (0.16 lb NO_x/MMBtu) and the relatively low exhaust gas temperatures (generally less than 510°F as described above). The controlled NO_x emission rate is calculated as follows:

0.26 lb/klb * (1 - 0.32) * 227,875 klb/yr ÷ 2000 lb/ton = 20.1 tpy each

6.4 Factor 1: Cost of Compliance

The cost of compliance analysis was based on a spreadsheet developed by EPA to implement the June 2019 update of the SNCR chapter of the EPA Control Cost Manual [13]. A printout of the completed spreadsheet, titled Air Pollution Control Cost Estimation Spreadsheet for SNCR, is included in Appendix C along with supporting information used in the analysis.

The SNCR cost estimate spreadsheet is designed for use with coal-, oil-, and natural gas-fired boilers. Bison has modified the spreadsheet for use with Interfor's hog fuel-fired boilers by using wood fuel characteristics instead of the fuel characteristics included in the spreadsheet. The higher heating value (HHV) of the hog fuel was adjusted to reflect the average moisture content of the fuel (42.8%) as determined during the 2017 B-1 stack test.

6.4.1 SNCR Data Inputs

The combustion unit is an existing industrial boiler – the addition of SNCR would be a retrofit installation. A retrofit factor of 1 was used to indicate that it would be expected to be a project of average retrofit difficulty. The fuel type box is blank because no default fuel information was used. The boiler heat input rate of 79.4 MMBtu/hr and the higher heating value (HHV) of the dry fuel is 8,878 Btu per pound or 17.75 MMBtu per bone dry ton (BDT). Actual annual fuel consumption is estimated to be 20,100 BDT/yr for each boiler.

The net plant heat input rate (NPHR) was set at 14.38 million Btu per megawatt-hour (MMBtu/MWh) based on the value for biomass in the Control Cost Manual guidance in section 1.3.1 [12].

The inlet NO_x emissions to the SNCR are 0.164 lb/MMBtu based on the average NO_x emissions measured at the two boilers during stack testing. A removal efficiency of 32% is assumed as explained above, and the outlet NO_x emissions from the SNCR would be 0.112 lb/MMBtu.

For this application, it was assumed that the SNCR would use urea, and the reagent values for urea in the spreadsheet are the default values. The cost values are based on the 2018 Chemical Engineering Plant Cost Index (CEPCI) value of 603.1, based on the annual average [14]. The currently published Prime Rate of 3.25% was used as the annual interest rate. The fuel cost for the hog fuel was estimated to be $2.01/MMBtu based on an average 2016 price of $32 per bone-dry ton (BDT) delivered [15] (corrected to 2018 dollars using the CEPCI) and a fuel high heating value (HHV) of 8,878 Btu/lb on a dry basis. Ash disposal cost for the additional fuel burned to drive the SNCR reaction was not included. The spreadsheet default costs for reagent, water and electricity were used in the analysis.

6.4.2 Cost Effectiveness Calculation Results

The cost calculation results show that the addition of SNCR to each of the Steam Plant hog fuel-fired boilers would have a cost effectiveness of $14,300 per ton of NO_x removed, in 2018 dollars. This value represents the cost of installing and operating SNCR add-on NO_x control technology in each of the Steam Plant boilers. If both boilers were retrofitted with SNCR, approximately 18 tons per year of NO_x emissions would be eliminated.

Table 6-1: Wood Fired Boiler Cost Effectiveness Analysis – NO_x

Control Technology	**% Reduction**	**Emissions (tons/year)**	**Emissions Reduction (tons/year)**
No NOx Control	Base Case	29.6 each 59.2 tpy combined	Base Case
Combustion Modification	Not feasible due to boiler age and design.		
Selective Catalytic Reduction	Not feasible due to boiler exhaust characteristics.		
Selective Non-catalytic Reduction	32.0%	20.1 tpy each 40.2 tpy combined	9.5 tpy each 19.0 tpy combined
SNCR Cost Parameters			
Boiler Steam Production Capacity	50,000 pounds of steam per hour each 100,000 pounds of steam per hour combined		
Boiler Heat Input Rate	79.4 million Btu per hour each 158.8 million Btu per hour combined		
Total Capital Investment	$1.24 million, each $2.48 Million, combined		
Total indirect annual costs, including capital recovery	$85,900 each $171,800 combined		
Total direct annual O&M Costs	$47,000 each $94,000 combined		
Total direct and indirect annual costs	$132,900/yr each $265,800 combined		
Cost per ton NO_x Removed	$132,900 ÷ 9.5 tpy = $14,300/ton $265,800 ÷ 19.0 tpy = $14,300/ton		

6.5 Factor 2: Time Necessary for Compliance

For SNCR, EPA states in its Control Cost Manual, “Installation of SNCR equipment requires minimum downtime. Although simple in concept, it is challenging in practice to design an SNCR system that is reliable, economical, and simple to control and that meets other technical, environmental, and regulatory criteria. Practical application of SNCR is limited by the boiler design and operating conditions.” [12] EPA also states in its 2008 Electric Generating Unit (EGU) NO_x Mitigation Strategies Proposed Rule Technical Support Document (TSD) for the Cross State Air Pollution Rule for the 2008 Ozone National Ambient Air Quality Standards (NAAQS) [16], that “SNCR … requires 12 months from contract award through commissioning.” In addition, SNCR would require additional time for “conceptual design, permitting, financing, and bid review.” Given that, Interfor estimates that SNCR retrofitting would require approximately 24 months for design, permitting, financing, etc. through commissioning.

6.6 Factor 3: Energy and Environmental Impacts of Compliance

SNCR presents several adverse environmental impacts. Unreacted ammonia in the flue gas (ammonia slip) and the products of secondary reactions between ammonia and other species present in the flue gas will be emitted to the atmosphere. Ammonia slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)_2SO_4$. Ammonium sulfate can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume.

An SNCR system would have a small energy penalty on the overall operation cost of the boiler. Costs for this energy expenditure are included in the discussion of Factor 1, cost of compliance.

6.7 Factor 4: Remaining Useful Life

The Interfor Dutch oven boilers were manufactured and installed at the Interfor Gilchrist sawmill in 1939. For this four-factor analysis, it has been assumed that the boilers have a remaining useful life of 20 years based on ODEQ guidance which stated that a 20-year planning horizon should be assumed for the purpose of the requested reasonable progress analysis. The only exception to this horizon is if there is a unit shutdown date identified that will cease operations before 20 years has expired.

7.0 COST EFFECTIVENESS COMPARISON

The EPA Draft Guidance on Progress Tracking [9] includes recommendations to rely on the cost effectiveness metric and comparisons to past regulatory actions. EPA recommends that a state consider the costs of compliance by comparing the cost/ton metric for a control measure to the same metric from other regulatory actions, in the manner explained in this section.

Cost effectiveness determinations are generally made to meet the requirements of Best Available Control Technology (BACT) regulations. BACT analyses are made on a case-by-case basis during site-specific industrial source permitting processes. The cost-effectiveness data for the BACT determinations is typically not included in the RBLC database. No publicly available cost information for BACT analyses on sources similar to the Interfor hog fuel boilers has been located.

Cost effectiveness determinations were also included in the regional haze Round 1 analysis to support best available retrofit technology (BART) determinations. The Oregon Round 1 analysis for regional haze focused on emissions control for a coal-fired power plant at Boardman, Oregon. The BART analysis for that facility concluded that emission control options costing more than $7,300 per ton would not be required [Federal Register Vol. 75, No. 128, July 5, 2011].

The Washington Round 1 regional haze analysis included BART analysis for two wood-fired power boilers. The evaluation found that replacement of the wet scrubber with a wet ESP on one boiler was not cost effective at a cost of $11,249/ton of PM_{10} removed. Washington also concluded that NO_x emissions controls costing $13,000/ton using SCR and $6,686/ton using SNCR would not be cost effective [Federal Register Vol. 77, No. 247, December 26, 2012].

The four-factor analysis for the Interfor wood-fired boilers has determined that adding an ESP to further control PM_{10} emissions would have an effectiveness cost of $12,500/ton. This is higher than the costs that were identified in the Oregon and Washington Round 1 regional haze analyses as not being cost effective for PM_{10} control.

The four-factor analysis for the Interfor wood-fired boilers has determined that adding an SNCR system to control NO_x would have an effectiveness cost of $14,300/ton. This is higher than the costs that were identified in the Oregon and Washington Round 1 regional haze analyses as not being cost effective for NO_x control.

8.0 CONCLUSIONS

A four-factor analysis has been conducted for the Interfor's wood-fired boilers at the Gilchrist, Oregon sawmill. The analysis was conducted to meet the requirements of Round 2 to assist ODEQ with the development of a SIP to address Regional Haze. Regional Haze requirements and goals are found in Section 169A of the Federal Clean Air Act and codified in 40 CFR 51.308(d)(1). To implement the requirement, ODEQ required Interfor to perform this analysis.

The four factors analyzed were based on the ODEQ correspondence and the RHR to determine if there are emission control options at the Gilchrist facility that, if implemented, could be used to attain reasonable progress toward the state's visibility goals. The factors reviewed included the cost of compliance, time necessary for compliance, energy and environmental impacts, and the remaining useful life of the existing source subject to these requirements.

Interfor considered all the emissions sources at the facility and found that the wood-fired boilers dominated the PM_{10}, NO_x and SO_2 emissions. The four-factor analysis was conducted for NO_x and PM_{10} on boilers B-1 and B-2 at the Gilchrist sawmill facility. SNCR installed on the boilers would have a cost effectiveness of $14,300 per ton of NO_x removed (in 2018 dollars). an ESP installed on each boiler would have a cost effectiveness of $12,500 per ton of PM_{10} removed. Both pollution control technologies generate some level of energy and other environmental impacts. Both types of control would take two or more years to fully implement.

Review of BART analyses prepared by Oregon and Washington state agencies for Round 1 of the regional haze process showed that the cost-effectiveness values were similar to those developed by Interfor. Oregon and Washington state agencies concluded that these costs were too high to be cost effective, and EPA agreed.

The primary contributors of PM_{10} emissions impacting Oregon Class I areas, including the Diamond Peak Wilderness, are wildfire, woodstove, and mobile source emissions. While difficult to control or even affect these sources, their impacts nonetheless dominate. Industrial point sources of emissions are an easy target; however, these facilities are providing the economic means that enable people to invest in cleaner burning woodstoves and vehicles. Prior to imposition of controls on industry, ODEQ needs to ensure that those requirements do not eliminate the good paying jobs that allow individuals to make better decisions regarding the innumerable smaller sources of PM pollution in Oregon.

9.0 REFERENCES

1. Interagency Monitoring of Protected Visual Environments (IMPROVE) data. Available at: http://vista.cira.colostate.edu/Improve/

2. IMPROVE data, PM and Haze Budgets. Available at: http://vista.cira.colostate.edu/Improve/pm-and-haze-composition/

3. 40 CFR 51.308(d)(1). Available at: https://www.ecfr.gov/cgi-bin/text-idx?SID=6be691f68b88f0969a5d1470739f740d&mc=true&node=se40.2.51_1308&rgn=div8

4. EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019. Available at: https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

5. 40 CFR 51.308, *et seq*. Available at: https://www.ecfr.gov/cgi-bin

6. IMPROVE Program, Regional Haze efforts. Available at: http://vista.cira.colostate.edu/Improve/improve-program/

7. EPA Control Cost Manual (Sixth Edition), Section 6 – Particulate Matter Controls, Chapter 2 – Wet Scrubbers for Particulate Matter, July 15, 2002. Available at: https://www3.epa.gov/ttn/ecas/docs/cs6ch2.pdf

8. EPA Control Cost Manual (Sixth Edition), Section 6 – Particulate Matter Controls, Chapter 3 – Electrostatic Precipitators, September 1999. Available at: https://www3.epa.gov/ttn/ecas/docs/cs6ch3.pdf

9. "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, EPA-457/P-16-001, July 2016. Available at: https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf

10. Western Regional Air Partnerships (WRAP), Regional Haze efforts. Available at: http://www.wrapair2.org/reghaze.aspx

11. EPA Control Cost Manual (Seventh Edition), Section 4 – NO_x Controls, Chapter 2 – Selective Catalytic Reduction, June 12, 2019. Available at: https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

12. EPA Control Cost Manual (Seventh Edition), Section 4 – NO_x Controls, Chapter 1 – Selective Non-Catalytic Reduction, April 25, 2019. Available at: https://www.epa.gov/sites/production/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf

13. EPA’s SNCR Cost Calculation Spreadsheet, June 2019. Available at: https://www.epa.gov/sites/production/files/2019-06/sncrcostmanualspreadsheet_june2019vf.xlsm

14. CHEMICAL ENGINEERING PLANT COST INDEX: 2018 ANNUAL VALUE By Scott Jenkins | March 20, 2019. Available at: https://www.chemengonline.com/2019-cepci-updates-january-prelim-and-december-2018-final/

15. Central Oregon Biomass Supply Availability Analysis, Table 19. Prepared for Central Oregon Intergovernmental Council by TSS Consultants, Rancho Cordova, California. June 6, 2016. https://coic2.org/wp-content/uploads/2015/12/coicbiomassavailabilityreport-final.pdf

16. EGU NO_x Mitigation Strategies Proposed Rule TSD, September 2015, https://www.epa.gov/sites/production/files/2015-11/documents/egu_nox_mitigation_strategies_tsd_0.pdf

APPENDIX A: COMMUNICATIONS WITH ODEQ

Oregon

Kate Brown, Governor

Department of Environmental Quality
Agency Headquarters
700 NE Multnomah Street, Suite 600
Portland, OR 97232
(503) 229-5696
FAX (503) 229-6124
TTY 711

Certified Mail

December 23, 2019

Interfor Pacific Inc.
Mill Manager
PO Box 638
Gilchrist, OR 97737-0638

Re: Regional Haze Four Factor Analysis; Interfor Gilchrist

Dear Interfor Pacific Inc.:

The purpose of this letter is to inform you that the Oregon Department of Environmental Quality (DEQ) has identified the Interfor Gilchrist as a as a significant source of regional haze precursor emissions to a Class I area in Oregon, thus triggering the need for a four factor analysis under the regional haze program. Please complete this analysis and submit it by May 31, 2020.

Background

The Oregon Department of Environmental Quality (DEQ) is required to develop and implement air quality protection plans to reduce the pollution that causes haze at national parks and wilderness areas, known as Federal Class I areas. This requirement can be found at 40 CFR 51.308 and 42 U.S.C. § 7491(b), and is implemented under the authority of ORS 468A.025.

DEQ submitted its first regional haze state implementation plan (SIP) in 2010 and is required to submit a revision in 2021 to address the second planning period, 2018-2028. In this revision, Oregon is required to update the long-term strategy that addresses regional haze visibility impairment in each of the twelve Class I areas within Oregon as well as the Columbia River Gorge National Scenic Area and those Class I areas outside of Oregon that are impacted by emissions from sources in Oregon.[1]

---

[1] The Class I Areas in Oregon are: Kalmiopsis Wilderness, Crater Lake National Park, Mountain Lakes Wilderness, Gearhart Mountain Wilderness, Diamond Peak Wilderness, Three Sisters Wilderness, Mount Washington Wilderness, Mount Jefferson Wilderness, Mount Hood Wilderness, Strawberry Mountain Wilderness, Eagle Cap Wilderness, and Hells Canyon Wilderness.

In establishing the long-term strategy, DEQ must evaluate and determine emission reduction measures necessary to make reasonable progress for each Class I area within Oregon. Per 40 CFR 51.308(f)(2) this evaluation should consider major and minor stationary sources, mobile sources, and area sources.

Guidance provided by the U.S. Environmental Protection Agency (EPA) indicates DEQ must address 80% of the visibility impairment caused by in-state sources.[2] Data from the EPA and National Park Service Visibility (IMPROVE) Program monitoring sites for Oregon's 12 Class I Areas indicate that sulfates, nitrates, and coarse mass continue to be significant contributors to visibility impairment in these areas. The primary precursors of sulfates, nitrates, and coarse mass are emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM_{10}).

DEQ has identified your facility as a significant source of regional haze precursor emissions. Based on the information in the table below, DEQ selected your facility to provide additional information about emissions and current and potential controls based on a screening evaluation of haze-causing emissions relative to distance to Class I Areas in Oregon.

DEQ Facility ID:	18-0005
Federal Facility ID:	8518711
Facility name:	Interfor Gilchrist
Facility Address	1 SAWMILL RD
Facility City, State, Zip	GILCHRIST, OR 97737

Facility 2017 Emissions[3]

Actual (tons per year)				Potential to Emit (tons per year)			
NOx	SO2	PM-10	Total Q	NOx	SO2	PM-10	Total Q
60.2	2.3	125.3	187.7	104	39	208	351

Pursuant to OAR 340-214-0110, by this letter DEQ is requiring you to provide information that will help DEQ prepare its updated long-term strategy. Specifically, you must complete a four factor analysis of potential additional controls of haze precursor emissions, as described below. DEQ will review submissions for adequacy and may revise as necessary. DEQ will need to be able to verify the information submitted in your four factor analysis. In order for DEQ to be able to approve your submission, please be sure to provide all supporting documents that are not publicly available, including emissions factors and calculation methods. DEQ will consider submissions incomplete if submitted without supporting information. The analysis should be

---

[2] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, (August 2019), EPA-457/B-19-003. pp. 31 – 34, https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period.

[3] Annual emissions data taken from the 2017NEIDRAFT data for stationary sources released August 2019 (https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data). Potential to emit information taken from facility permits in TRAACS.

prepared using the EPA guidance referenced above as well as EPA's Air Pollution Control Cost Manual[4] and EPA's Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze.[5] Please complete the analysis for every emission point at your facility. If a unit is too small to control, please demonstrate that.

If you fail to submit your four factor analysis to DEQ by May 31, 2020, you may be subject to enforcement, including civil penalties.

Four Factor Analysis

Based on our evaluation, your facility warrants an analysis to be included in DEQ's SIP submittal, which could mean that additional emission controls will be required. As outlined in 40 CFR 51.308(f)(2), DEQ must evaluate four factors to determine whether specific control measures for your facility are reasonable and should be included in an updated long-term strategy. By this letter, DEQ is requiring you to provide information and analysis of the four factors. These four factors are:

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.

DEQ looks forward to your submittal of a four factor analysis for these emission units and pollutants as soon as practicable, but no later than May 31, 2020. We encourages you to share drafts with us for comments and we are prepared to engage in consultation to ensure an approvable submittal before the deadline.

DEQ will host an **informational webinar on the Regional Haze Program and the four factor analysis** at 10:00 am on January 9, 2020. The conference call and webinar information is as follows: Call in number: 888-557-8511; Participant Code: 9544452; Web link: https://www.teleconference.att.com/servlet/AWMlogin

For more information, please see https://www.oregon.gov/deq/aq/Pages/Haze.aspx.

Contact

If you have questions or would like to meet, please contact D Pei Wu, PhD at wu.d@deq.state.or.us or (503) 229-5269.

---

[4] EPA, "EPA Air Pollution Control Cost Manual." https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution. Please refer to the most current finalized version of the relevant chapters.

[5] EPA, "Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, and Regional Haze," November 2018, EPA-454/R-18-009. https://www.epa.gov/scram/state-implementation-plan-sip-attainment-demonstration-guidance

Sincerely,

Ali Mirzakhalili
Air Quality Division Administrator

Cc:

Richard Whitman, Director, Oregon Department of Environmental Quality
Michael Orman, Air Quality Planning Manager
D Pei Wu, Air Quality Planner

APPENDIX B: ELECTROSTATIC PRECIPITATOR COST ANALYSIS CALCULATIONS

Interfor Gilchrist Mill
Regional Haze Four-Factor Analysis
PM10 Control Electrostatic Precipitator (ESP)

Key

Blue values are entered
Green values are referenced
Red values are calculated

Design Basis - Per Boiler (Boilers B-1 and B-2)

			Source*
Pollutant source	Boiler		
Fuel	Hogfuel		
Flow, max	80,400	ACFM	1
Temperature	500	deg. F	2
Basis of ton/yr calculations	8760	hr/yr	
Assumed equipment life	20	years	3
PM10 emissions exiting multiclone	0.50	lb/klb	4
	227,875	klb/yr	5
	57.0	ton/yr	
BACT ESP emission lLimits, expected emission rate			
PM10 emissions exiting ESP	0.080	lb/klb	6
	9.1	ton/yr	
PM10 removal efficienty	84.0%		

Assumptions about ESP Equipment

Flat Plate ESP - Per the EPA Control Cost Manual, Section 3.1.2.2

https://www.in2013dollars.com/us/inflation/1999?endYear=2018&amount=100

Section 3.2.1.2 Full SCA Procedure, EPA Cost Control Manual, September 1999

Step 1

Design collection efficiency

inlet load: 0.50 lb/klb
potential outlet load: 0.080 lb/klb

Eff (%) Eff (%) = 100 x (1 - (outlet load/inlet load)) = 84.0 %

Step 2

Design penetration

p p = 1 - (Eff/100) = 0.160 %

Step 3

Operating temperature in Kelvin, K

approximate stack temperature: 500 deg F

T_K T_K = (T_F +459.67)/1.8 = 533 K

Step 4

Assume severe back corona is **not** present

Step 5

Mass median diameter of inlet particle distribution (MMDi)

MMDi	From Table 3.5, wood burning boiler, MMDi =	5	um

Step 6

Sneakage, S_N, and rapping reentrainment, RR

For flat plate ESP

S_N	From Table 3.6	S_N =	0.10	flat plate
RR	From Table 3.7	RR =	0.14	(not known)

Step 7

Assume values for most penetrating size (MMDp) and rapping puff size (MMDr)

MMDp	MMDp =	2	um
MMDr	MMDr =	4	(since MMDi = 5, chose the average of the > 5 & < 5 options)

Step 8

Use/compute the following factors for pure air:

esp_0	eps_0 =	8.845E-12	(F/m) free space permittivity
eta	eta = 1.72e-5*(T_K/273)^0.71 =	2.76641E-05	(kg/(m*s)) gas viscosity
E_bd	E_bd = 630,000*(273/T_K)^1.65 =	208,789	(V/m) electric field at sparking
LF	LF = S_N + RR*(1-S_N) =	0.226	dimensionless loss factor

For flat plate ESPs:

E_avg	E_avg = E_bd * 5/6.3 =	165,705	average field, no back corona, + polarity

Step 9

Assume the smallest number of sections for the ESP, n, such that LF^n < p

n	**LF^n**		**p =**	0.160
1	0.226	>p		
2	0.051	< p		
3	0.012	< p		

n n = 2

Step 10

Average section penetration

p_s p_s = p^(1/n) = 0.400

Step 11

Section collection penetration

p_c p_c = (p_s - LF)/(1 - LF) = 0.2248

Step 12

Particle size change factors, D and MMDrp

D	D = p_s = S_N + p_c*(1 - S_N) + RR*(1-S_N)*(1 - p_c) =	0.400
MMDrp	MMDrp = RR*(1 - S_N)*(1 - p_c)*(MMDr/D) =	0.977

Step 13

Table of particle sizes for sections 1 through n

	Section	MMDs	
MMD1	1	MMD1 = MMDi =	5
MMD2	2	MMD2 = {MMD1*S_N + [(1 - p_c)*MMDp + p_c*MMD1]*p_c}/D + MMDrp =	3.730

Step 14

Calculate the specific collection area (SCA) for sections 1 through n

SCA_1 = -(eta/eps_0)*(1-S_N)*ln(p_c)/(E_avg^2 * MMD1 *10^(-6)) = 30.60 s/m

SCA_2 = SCA_1 * MMD1/MMD2 = 41.02 s/m

Step 15

Calculate total SCA and the English SCA, ESCA

SCA(s/m) = SCA_1 + SCA_2 = 71.62 s/m area/volumentric flow rate

ESCA (ft^2/kacfm) = 5.080 * SCA (s/m) = 363.85 ft^2/kacfm

Maximum gas flow from boiler: 80 kacfm

Plate area: 29,253 ft^2

From Figure 3.5:

Equation: 891.10*(ft^2)^0.6276 = Price - $, second quarter 1987 7

Flange-to-flange, field-erected, with standard options: $ 566,105 1987 dollars

U.S. Bureau of Labor Statistics - Producer Price Index

Series ID: PCU33341333341311 Dust collection and other air purification equipment for industrial gas cleaning systems

Based on NAICS: 333413 Fan, blower, air purification equipment mfg

Base year: 1983 index = 100

Data available for 1989 through 2020 (1990 is the first year with full annual data)

Linearly interpolate between 1983 and 1990 to estimate index for 1987:

PPI for 1987 = 114.4 - (114.4-100)/(1990-1983)*(1990-1987) = 108.2

PPI for Jan. 2020: 206.8

Adjustment ratio = Jan. 2020 PPI/1987 PPI = 1.91

Adjusted cost: $ 1,081,698 2020 dollars

COST ESTIMATE

Cost Item	**Factor**			**Source***
<u>Total Capital Investment, TCI</u>				
ESP + auxiliary equipment				
Flange-to-flange, field-erected, standard options, 2020 $		$ 1,081,698		
New cones in multiclone		$ -	Excluded	8
ID Fan		$ -	Excluded	
ESP + auxiliary equipment	A	$ 1,081,698		

Direct Costs					
Purchased Equipment Cost, PEC					
ESP + auxiliary equipment	A	$	1,081,698		3
Instrumentation	0.10 A	$	108,170		3
Sales taxes	0.03 A	$	32,451		3
Freight cost	0.05 A	$	54,085		3
Purchased Equipment Cost, PEC	B	$	1,276,403		3
Direct installation costs					
Foundation and supports	0.04 B	$	51,056		3
Handling and erection	0.50 B	$	638,202		3
Electrical	0.08 B	$	102,112		3
Piping	0.01B	$	12,764		3
Insulation for ductwork	0.02 B	$	25,528		3
Painting	0.02B	$	25,528		3
Direct installation costs	0.67 B	$	855,190		3
Required electrical utility upgrade		$	25,000		9
Basis: Interfor Electrical Supervisor, Todd Hester Cost estimate via email dated 3/2/2020					
Site preparation		As required, SP			
Buildings		As required, Bldg.			
Total Direct Costs, DC	1.67 B + Electrical upgrade + SP + Bldg.	$	2,156,594	+ SP + Bldg.	
Indirect Costs (installation)					
Engineering	0.20 B	$	255,281		3
Construction and field expenses	0.20 B	$	255,281		3
Contractor fees	0.10 B	$	127,640		3
Start-up	0.01 B	$	12,764		3
Performance test	0.01 B	$	12,764		3
Model study	0.02 B	$	25,528		3
Contingencies	0.03 B	$	38,292		3
Total Indirect Costs, IC	0.57 B	$	727,550		3
Total Capital Investment, TCI = DC + IC					
	2.24 B + Electrical Upgrade (no SP, no Bldg.)	$	2,884,144	**2020 dollars**	
Retrofit Cost Factor, RCF	1.4				3
TCI in 2020 dollars and with RCF		**$**	**4,037,801**		

Total Annual Costs, TAC

Direct Annual Cost

Operating labor, coordination					$	19,488		
Basis:	Annual mean wage	$	97,440					10
	Fraction of ESP time		0.2					11
	Fraction of ESP time * annual labor cost							3
Operating labor, per shift					$	37,734		
Basis:	Mean hourly wage	$	17.23	/hr				12
	Labor per shift		2	hr/shift				3
	Number of shifts		3	shift/day				11
	Operating days		365	day/year				11
Total operating labor					$	57,222		
Supervisory labor				0.15 L	$	8,583		3
				Total Annual Labor	**$**	**65,805**		
Maintenance labor					$	11,372		3
Basis:	Maintenance labor estimated at:							3
			15	h/wk				3
			44	wk/yr				3
	Same wage as above	$	17.23	/hr				
Maintenance materials				0.01 * Equip cost	$	10,817		3
Basis:	Equip cost = A above	$	1,081,698					
				Total Annual Maintenance	**$**	**22,189**		
Electricity (ESP)					$	8,487	annual full load	
Basis:	Full load power use		14	kW				13
	Electricity ($Cost_{elect}$)		0.0692	$/kWh				14
Electricity (ID Fan)					$	8,822		
Basis:	fan kWh/yr = 0.000181*ACFM*delta P*hr/yr							3
	ACFM from above:		80,400	ACFM				
	delta P, estimate:		1.0	in. H2O				11
			8760	hr/yr				
	fan kWh/yr =		127,479	kWh/yr				
	Annual cost = fan kWh/yr * $/kWh (above)							

Direct Annual Costs Summary

Total Annual Labor	$	65,805
Total Annual Maintenance	$	22,189
Electricity (ESP)	$	8,487
Electricity (ID Fan)	$	8,822
Total Direct Annual Costs	**$**	**105,302**

Indirect Annual Costs

Capital recovery costs			$	277,801	
Basis:	Capital Recovery Factor (CRF) * TCI				3
	CRF = i $(1+ i)^n/((1+ i)^n - 1)$ =	0.0688			3
	Where n = Equipment Life and i= Interest Rate				3
	Annual Interest Rate (i), percent	3.25			15
Administrative charges (includes taxes, insurance)			$	161,512	
Basis:	0.04 * TCI				3
Overhead			$	52,796	
Basis:	60% * (operating + supervisory + coordination + maintenance labor + maintenance materials)				3

From above:

labor	operating	$	37,734
	supervisory	$	8,583
	coordination	$	19,488
	maintenance	$	11,372
materials	maintenance	$	10,817
		$	87,994

Indirect Annual Costs Summary

Capital recovery costs	$	277,801
Administrative charges (includes taxes, insurance)	$	161,512
Overhead	$	52,796
Total Indirect Annual Costs	**$**	**492,109**

Total Annual Costs Summary

Total Direct Annual Costs	$	105,302	
Total Indirect Annual Costs	$	492,109	
Total Annual Cost	**$**	**597,411**	
Tons per year PM10 removed		47.9	
Cost Effectiveness	$	12,484	/ton PM_{10} removed

*Sources:

1 Based on September 2012 stack test, Boiler 1-2: avg 61,450 ACFM during testa * (50klb steam nominal capacity/avg 45.3 klb steam during tests) = 68,000 acfm design

2 Approximate average stack temperature of Boiler 1 and Boiler 2 exhaust during the 2012, 2016, and 2017 stack tests.

3 EPA Control Cost Manual, Section 6 Particulate Matter Controls, Chapter 3 Electrostatic Precipitators. September 1999. Also, Oregon DEQ regional haze guidance: https://www.oregon.gov/deq/aq/Documents/Haze-FourFactorAnlaysis.pdf

4 Emission factor for PM10, Permit Number 18-0005-TV-01, based on and verified by peformance testing

5 boilers during 2016 and 2017 (455,750 klb/yr) as reported in the Annual Report for those years, divided by two to represent one of the two boilers (455,750 klb/yr / 2 boilers = 227,875 klb/yr / boiler)
.

6 RBLC ME-0040 BACT Determination, PM10 (front and back half), 0.05 lb/MMBtu

7 Turner, J.H., P.A. Lawless, T. Yamamoto, D.W. Coy, G.P. Greiner, J.D. McKenna, and W.M. Vatavuk (1988) Sizing and Costing of Electrostatic Precipitators, Part II: Costing Considerations. JAPCA, 38:5, 715-726, DOI: 10.1080/08940630.1988.10466413

8 Interfor purchase order, project number 201710

9 $50,000 would upgrade the electrical for both ESPs - personal communication with Interfor Electrical Supervisor

10 May 2018 State Occupational Employment and Wage Estimates Oregon, U.S. Bureau of Labor Statistics https://www.bls.gov/oes/2018/may/oes_or.htm , occupation code 17-2081, Environmental Engineers

11 Estimate

12 May 2018 State Occupational Employment and Wage Estimates Oregon, U.S. Bureau of Labor Statistics https://www.bls.gov/oes/2018/may/oes_or.htm , occupation code 51-7041, Sawing Machine Setters, Operators, and Tenders, Wood

13 Firm quote for two PPC Model 11R-1120-1712S modular electrostatic precipitators obtained by Interfor in 2016 - provides an estimate of EPS power consumption

14 Table 2.4 - 2018 Average Price of Electricity for industrial customers - https://www.eia.gov/electricity/annual/pdf/epa.pdf

15 Prime Rate as of Mar 16, 2020 - https://www.hsh.com/indices/prime-rate.html

APPENDIX C: SELECTIVE NON-CATALYTIC REDUCTION COST ANALYSIS CALCULATIONS

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

<u>Step 1</u>: 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.

<u>Step 2</u>: 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.

<u>Step 3</u>: 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.

<u>Step 4</u>: 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.

<u>Step 5</u>: 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? Industrial ▼

What type of fuel does the unit burn? ▼

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 maximum heat input rate (QB)? 79.4 MMBtu/hour

What is the higher heating value (HHV) of the fuel? 17,756,000.00 Btu/ton

What is the estimated actual annual fuel consumption? 20,100 ton/year

Is the boiler a fluid-bed boiler? No ▼

Enter the net plant heat input rate (NPHR) 14 MMBtu/MWh

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
Biomass	14.38 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned: ▼

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

or

Select the appropriate SO_2 emission rate: ▼

Ash content (%Ash): 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.

	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
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.164	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.112	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	1.99	

Plant Elevation	4500	Feet above sea level

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	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: Urea ▼

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)	3.25	Percent
Fuel ($Cost_{fuel}$)	2.01	\$/MMBtu
Reagent ($Cost_{reag}$)	1.66	\$/gallon for a 50 percent solution of urea*
Water ($Cost_{water}$)	0.0042	\$/gallon*
Electricity ($Cost_{elect}$)	0.0676	\$/kWh*
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)		\$/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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	Check with reagent vendors for current prices.
Water Cost ($/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 ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at http://www.eia.gov/electricity/data.cfm#sales.
Fuel Cost ($/MMBtu)	-	Select fuel type	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)	-	Select fuel type	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)	-	Select fuel type	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)	-	Select fuel type	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)	-	Select fuel type	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 (%)	3.25	Default bank prime rate	Use current bank prime rate available at https://www.federalreserve.g

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 =	79.4	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	39,172	ton/year	
Actual Annual fuel consumption (Mactual) =		20,100	ton/year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.44		
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 =	4495	hours	
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	32	percent	
NOx removed per hour =	NOx_{in} x EF x Q_B =	4.13	lb/hour	
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	9.28	tons/year	
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)			Not applicable; factor applies only to coal-fired boilers
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =			Not applicable; factor applies only to coal-fired boilers
Elevation Factor (ELEVF) =	14.7 psia/P =	1.18		
Atmospheric pressure at 4500 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	Urea	Molecular Weight of Reagent (MW) =	60.06 g/mole
		Density =	71 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)	17	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	34	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	3.6	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	1,200	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	0.0688

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	0.8	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 x $m_{reagent}$ x ((1/C_{inj})-1) =	0.14	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/HHV =	0.0	lb/hour

Not applicable - Ash disposal cost applies only to coal-fired boilers

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	$460,477 in 2018 dollars
Air Pre-Heater Costs (APH_{cost})* =	$0 in 2018 dollars
Balance of Plant Costs (BOP_{cost}) =	$494,071 in 2018 dollars
Total Capital Investment (TCI) =	$1,240,912 in 2018 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 ($SNCR_{cost}$) =	$460,477 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}) =	$0 in 2018 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}) =	$494,071 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$46,969	in 2018 dollars
Indirect Annual Costs (IDAC) =	$85,933	in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$132,902	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 =	$18,614	in 2018 dollars
Annual Reagent Cost =	q_{sol} x Cost_{reag} x t_{op} =	$26,559	in 2018 dollars
Annual Electricity Cost =	P x Cost_{elect} x t_{op} =	$257	in 2018 dollars
Annual Water Cost =	q_{water} x Cost_{water} x t_{op} =	$304	in 2018 dollars
Additional Fuel Cost =	ΔFuel x Cost_{fuel} x t_{op} =	$1,236	in 2018 dollars
Additional Ash Cost =	ΔAsh x Cost_{ash} x t_{op} x (1/2000) =	$0	in 2018 dollars
Direct Annual Cost =		$46,969	in 2018 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$558	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$85,375	in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$85,933	in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$132,902	per year in 2018 dollars
NOx Removed =	9	tons/year
Cost Effectiveness =	$14,322	per ton of NOx removed in 2018 dollars