REGIONAL HAZE FOUR-FACTOR ANALYSIS

COLLINS PRODUCTS, LLC—KLAMATH FALLS FACILITY

Prepared for
COLLINS PRODUCTS, LLC
KLAMATH FALLS FACILITY
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ACRONYMS AND ABBREVIATIONS

\$/ton	dollars per ton of pollutant controlled
°F	degrees Fahrenheit
Analysis	Regional Haze Four Factor Analysis
CAA	Clean Air Act
CFR	Code of Federal Regulations
Control Cost Manual	USEPA Air Pollution Control Cost Manual
Collins	Collins Products, LLC
DEQ	Oregon Department of Environmental Quality
ESP	electrostatic precipitator
existing permit	Title V Operating Permit No. 18-0013-TV-01
facility	wood products manufacturing facility located at 6410 Highway 66, Klamath Falls, Oregon 97601
Federal Guidance Document	Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003
HAP	hazardous air pollutant
HB	hardboard
MFA	Maul Foster & Alongi, Inc.
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO	nitric oxide
NO_X	oxides of nitrogen
PB	particleboard
PCWP MACT	Plywood and Composite Wood Products Maximum Achievable Control Technology
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns or less
RCO	Regenerative Catalytic Oxidizer
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
USEPA	U.S. Environmental Protection Agency
VOC	volatile organic compound

1 INTRODUCTION

The Oregon Department of Environmental Quality (DEQ) is developing a State Implementation Plan (SIP) as part of the Regional Haze program in order to protect visibility in Class I areas. The SIP developed by the DEQ covers the second implementation period ending in 2028, and must be submitted to the U.S. Environmental Protection Agency (USEPA) for approval. The second implementation period focuses on making reasonable progress toward national visibility goals, and assesses progress made since the 2000 through 2004 baseline period.

In a letter dated December 23, 2019, the DEQ requested that 31 industrial facilities conduct a Regional Haze Four Factor Analysis (Analysis). The Analysis estimates the cost associated with reducing visibility-impairing pollutants including, particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), oxides of nitrogen (NO_X), and sulfur dioxide (SO_2). The four factors that must be considered when assessing the states' reasonable progress, which are codified in Section 169A(g)(1) of the Clean Air Act (CAA), are:

(1) The cost of control,

(2) The time required to achieve control,

(3) The energy and non-air-quality environmental impacts of control, and

(4) The remaining useful life of the existing source of emissions.

The DEQ has provided the following three guidance documents for facilities to reference when developing their Analysis:

1) USEPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003 (Federal Guidance Document).

2) USEPA Air Pollution Control Cost Manual, which is maintained online and includes separate chapters for different control devices as well as several electronic calculation spreadsheets that can be used to estimate the cost of control for several control devices (Control Cost Manual).

3) Modeling Guidance for Demonstrating Air Quality Goals for Ozone, particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$), and Regional Haze (November 2018), EPA-454/R-18-009.

The development of this Analysis has relied on these guidance documents.

1.1 Facility Description

Collins Products, LLC (Collins) owns and operates a wood products manufacturing facility located at 6410 Highway 66, Klamath Falls, Oregon 97601 (the "facility"). The facility produces hardboard (HB) and particleboard (PB). The facility currently operates under Addendum No. 4 to Oregon Title V

Operating Permit No. 18-0013-TV-01 issued by the DEQ on March 14, 2019. The facility is a major source of criteria pollutants and hazardous air pollutants (HAPs). As a result, the facility is subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Plywood and Composite Wood Products, codified in Title 40 Code of Federal Regulations (CFR) Part 63 Subpart DDDD (PCWP MACT). Compliance with the limits and controls associated with this standard require controls that result in significant particulate reductions.

The facility is located just outside the urban growth boundary of Klamath Falls. The urban growth boundary is also the administrative boundary of the Klamath Falls maintenance area for PM_{10} and carbon monoxide. However, the facility is located inside the Klamath Falls nonattainment area for $PM_{2.5}$. The nearest federal Class I Area is the Mountain Lakes Wilderness Area, approximately 24 kilometers northwest of the facility.

1.2 Process Description

1.2.1 Particleboard Plant

Raw materials are delivered to the facility by truck. Raw materials, or furnish (e.g., green and pre-dried wood shavings, sawdust, and chips), are stored, sorted by size, and dried. Dried furnish is separated into core or face grade material. The core and face materials are mixed and blended with formaldehyde free resin, formed into mats, and pressed into boards. Boards are then cooled, sanded, and cut to final product dimensions. Fine particulate emissions generated by all major process equipment, except for the press vent area and two process cyclones, are controlled by fabric filters. Emissions from the press are controlled by a Bio-Reactions BioSystem (biofilter).

1.2.2 Hardboard Plant

The primary processes at the HB plant include raw material receipt, fiber production, mat forming, pressing, baking, humidification, sizing and coating. Raw materials for the HB process include wood by-products of various species. The wood chips are processed through defibrators, where they are blended with resin, producing resinated fibers. Resinated fibers are formed, pressed, baked, humidified and then allowed to cool. Trimmed hardboard siding is coated with a water-based primer coat and oven dried. Emissions from the press and the defibrators are controlled by a combination of cyclones, water sprays, baghouses and a Tri-Mer BioSystem (biofilter).

2 APPLICABLE EMISSION SOURCES

Collins retained Maul Foster & Alongi, Inc. (MFA) to assist the facility with completing this Analysis. Emissions rates for each visibility-impairing pollutant (PM_{10}, NO_X, and SO_2) were tabulated. These emissions rates represent a reasonable projection of actual source operation in the year 2028. As stated in the Federal Guidance Document,[1] estimates of 2028 emission rates should be used for the Analysis. It is assumed that current potential to emit emission rates at the facility represent the most reasonable estimate of actual emissions in 2028.

After emission rates were tabulated for each emissions unit, estimated emission rates for each pollutant were sorted from the highest emission rate to the lowest. The emission units collectively contributing at least 90 percent of the total facility emissions rate for a single pollutant were identified and selected for the Analysis.

This method of emission unit selection ensures that larger emission units are included in the Analysis. Larger emission units represent the likeliest potential for reduction in emissions that would contribute to a meaningful improvement in visibility at federal Class I areas. It would not be reasonable to assess many small emission units—neither on an individual basis (large reductions for a small source likely would not improve visibility and would not be cost effective), nor on a collective basis (the aggregate emission rate would be no greater than 10 percent of the overall facility emissions rate, and thus not as likely to improve visibility at federal Class I areas, based solely on the relatively small potential overall emission decreases from the facility).

The following sections present the source selection, associated emission rates that will be used in the Analysis, and pertinent source configuration and exhaust parameters.

2.1 Sources of PM_{10} Emissions

A summary of the selected emission units and associated PM_{10} emission rates included in the analysis is presented in Table 2-1 (attached). A detailed description of each emissions unit is presented below. The permit emission unit ID is shown in parentheses.

2.1.1 HB Defibrators/Dryers 1 through 4 (HB01, HB02, HB03, HB04)

Wood chips are processed through four defibrators where they are blended with resin and dried. Process exhaust from HB Defibrators/Dryers 1, 2, and 3 is routed to individual cyclones, followed by multiple in-duct water sprays, followed by a Tri-Mer BioSystem (biofilter). Process exhaust from HB04 is routed to a cyclone, followed by a baghouse, followed by multiple in-duct water sprays, followed by a biofilter. HB Defibrators/Dryers 1, 2, 3 and 4 are subject to PCWP MACT. Because they are already fully controlled sources for PM_{10} emissions, HB01, HB02, HB03 and HB04 will be excluded from further evaluation in the Analysis.

2.1.2 PB Surface Dryers (PB06)

Surface material is conveyed to two flash tube PB surface dryers. Each PB surface dryer is indirectly heated so there are no entrained combustion emissions. The dryer process exhaust is controlled by a downstream baghouse (control device ID PB44).

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[1] See Federal Guidance Document page 17, under the heading "Use of actual emissions versus allowable emissions."

Both PB surface dryers will be excluded from additional analysis for PM control as they are already equipped with best-in-class pollution control technology, which they are required to operate under the federally-enforceable Title V permit. These dryers are also subject to PCWP MACT. Additionally, the surface dryers have potential annual PM_{10} emissions of only 2.54 tons/year. Given the flowrate from this source, MFA is unaware of any additional particulate controls that could be cost effectively applied given the high efficiency of the existing baghouse controls.

2.1.3 HB Cyclone 7 (HB10)

HB cyclone 7 is used to control particulate emissions generated by the former wire negative air system. The exhaust stream enters the cyclone and centrifugal forces are imparted on larger-diameter particles in the conical chamber. The centrifugal forces influence the larger-diameter particles to move toward the cyclone walls, resulting in collection of PM at the bottom of the cone. Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone.

2.1.4 HB Cyclone 23 (HB14)

HB cyclone 23 is used to control displaced air during loading and unloading of wood chip storage silos 1, 2 and 3. Silos 1, 2 and 3 store raw wood chips from the chipyard before processing. These raw wood chips have a high moisture content and are assumed to generate minimal PM during loading and unloading processes. Displaced air enters HB cyclone 23 where larger-diameter particles impact the conical chamber and are collected at the bottom of the cone. Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone.

2.1.5 HB Cyclone 27 (HB15)

HB cyclone 27 is used to control particulate emissions generated by the core metering belt shaver system. The fiber exhaust stream enters the cyclone and centrifugal forces are imparted on larger-diameter particles in the conical chamber. The centrifugal forces influence the larger-diameter particles to move toward the cyclone walls, resulting in collection of PM at the bottom of the cone. Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone.

2.1.6 HB Bake Oven (HB08) and HB Bake Oven Roof Vents (HB09)

The HB bake oven (HB08) is heated by natural gas-fired combustion and was installed after 1970. The HB bake oven roof vents are situated above emission unit HB08, the hardboard bake oven. Process exhaust from HB08 is routed to the Regenerative Catalytic Oxidizer (RCO) for control of volatile organic compound (VOC) emissions. Entrained filterable and condensable particulate emissions are also combusted in the RCO. and the potential to emit of the RCO is only 2.4 tons/year. Operation of the RCO is required in order to demonstrate compliance with PCWP MACT and the federally-enforceable Title V permit requires continuous parametric monitoring of the device. MFA is unaware of any additional particulate controls that could be cost effectively applied to HB08 given the high efficiency of the existing RCO. Therefore, HB08 will be excluded from additional analysis for PM control.

Racks inside the oven act as a seal during operation. At the end of each cycle as racks are pushed out and new racks are pushed in, fugitive emissions are released to atmosphere through the nearby roof vents (HB09).

2.1.7 PB Core Dryers (PB05)

Core materials are conveyed to two rotary drum PB core dryers. Each PB core dryer is heated by natural gas-fired combustion with a maximum rated design capacity of 10.36 million British thermal units per hour. The moisture content of core material entering the PB core dryers is a maximum of 30 percent moisture and exits with approximately 10 percent moisture. Operating temperature is limited to 600°F. The temperature and moisture limits are required by PCWP MACT and the federally-enforceable Title V permit to minimize the formation of organic emissions that would also form condensable particulate. The combined natural gas-fired burner and dryer process exhaust is controlled by two downstream baghouses (control device IDs PB3 and PB4) which were installed in 1995.

Both PB core dryers will be excluded from additional analysis for PM control as they are already equipped with best-in-class pollution control technology, which they are required to operate under the federally-enforceable Title V permit.

2.1.8 PB Press and Unloader (PB01)

The 14-opening PB press applies heat and pressure to activate the resin in order to bond the wood fibers into solids boards. The PB press produces particleboard ranging between 3/8" to 2-3/16” thick. The PB press was installed after 1970.

Fugitive process exhaust produced by the particleboard presses is routed to the PB biofilter. Testing was conducted by the facility to determine the PM, PM_{10} and $PM_{2.5}$ emission reductions and PM emission reduction credits were allowed based on the results. PB01 is subject to PCWP MACT and is required by the federally-enforceable Title V permit to operate the PB biofilter in order to maintain compliance with that standard. In addition, Addendum No. 3, dated April 6, 2018, to Title V Operating Permit expressly requires that the PB biofilter be operated and maintained as a particulate emissions control device.

2.1.9 PB Trim Saw (PB03)

The PB trim saw is used to trim particleboard sides and ends to final product dimensions. Uncontrolled fugitive particulate emissions are release to atmosphere by nearby roof vents.

2.1.10 PB Cyclone 24 (PB24)

Wood dust from the board trimming process are pneumatically conveyed to process PB cyclone 24, which separates larger-diameter particles from the exhaust stream. Centrifugal forces influence the larger-diameter particles to move toward the cyclone walls, resulting in collection of the larger-diameter wood dust at the bottom of the cone. Collected materials are pneumatically conveyed to PB cyclone 15, which dumps collected material to the reclaim storage pile. Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone.

2.1.11 Cyclones with Secondary Filters (PB10)

The cyclones with secondary filters handle sanderdust from the board finishing area in the PB plant. Sanderdust from the board finishing process is pneumatically conveyed to PB cyclone 10, which separates larger-diameter particles from the exhaust stream. The exhaust stream exiting the top of PB cyclone 10 is routed to a downstream baghouse for control of fine particulate emissions. The particleboard cyclones with secondary filters will be excluded from additional analysis for PM control as they are already equipped with best-in-class pollution control technology, which they are required to operate under the federally-enforceable Title V permit. Additionally, PB10 has potential annual PM_{10} emissions of only 2.98 tons/year. Given the flowrate from this source, MFA is unaware of any additional particulate controls that could be cost effectively applied given the high efficiency of the existing baghouse controls.

2.2 Sources of SO_2 Emissions

A summary of the selected emission units and associated SO_2 emission rates to be evaluated in the Analysis is presented in Table 2-2 (attached). The Title V review report (page 37 of 92) still identifies the facility as having the potential to emit 49.3 tons/year of SO_2 from PB05 based on the combustion of 1.39 million gallons of fuel oil annually. In fact, the fuel oil infrastructure has been removed and as the Title V review report (page 39 of 92) shows, the last time that fuel oil was combusted in the PB core dryers was in 2000 when 333 gallons were consumed. As the PB core dryers no longer have the capacity to burn fuel oil and are now only capable of burning natural gas, the potential to emit equals the device's maximum capacity to emit SO_2 while burning natural gas. References to fuel oil combustion by the PB core dryers will be removed as part of the permit renewal currently underway. The PB core dryers have a combined maximum heat input of 20.7 MMBtu/hr which limits the dryers to an SO_2 potential to emit of 0.5 tons/year. Given that the reductions for small sources likely would not improve visibility and would not be cost effective, these activities will not be evaluated further in the Analysis.

2.3 Sources of NO_X Emissions

A summary of the selected emission units and associated NO_X emission rates to be evaluated in the Analysis is presented in Table 2-3 (attached). As noted in Section 2.2, the PB core dryers no longer have the ability to burn fuel oil. The PB core dryers have a combined maximum heat input of 20.7

MMBtu/hr which limits the dryers to a NOx potential to emit of 8.9 tons per year when burning natural gas.

Because of the limited combustion sources at the facility, the Title V permit contains a generic PSEL for NOx of 39 tons/year. Actual emissions are substantially lower (6.9 tons in 2019). Given that the reductions for small sources likely would not improve visibility and would not be cost effective, these activities will not be evaluated further in the Analysis.

2.4 Emissions Unit Exhaust Parameters

A summary of the emission unit exhaust parameters to be evaluated further in this Analysis is presented in Table 2-4 (attached). Emission units identified in the preceding sections as infeasible for control, already equipped with best-in-class control technologies or otherwise exempt are not presented. These emissions units will not be evaluated further in this Analysis.

3 REGIONAL HAZE FOUR FACTOR ANALYSIS METHODOLOGY

This Analysis has been conducted consistent with the Federal Guidance Document, which outlines six steps to be taken when addressing the four statutorily required factors included in the Analysis. These steps are described in the following sections.

3.1 Step 1: Determine Emission Control Measures to Consider

Identification of technically feasible control measures for visibility-impairing pollutants is the first step in the Analysis. While there is no regulatory requirement to consider all technically feasible measures, or any specific controls, a reasonable set of measures must be selected. This can be accomplished by identifying a range of options, which could include add-on controls, work practices that lead to emissions reductions, operating restrictions, or upgrades to less efficient controls, to name a few.

3.2 Step 2: Selection of Emissions

Section 2 details the method for determining the emission units and emission rates to be used in the Analysis. Potential to emit emission rates were obtained from the existing permit review report.

3.3 Step 3: Characterizing the Cost of Compliance (Statutory Factor 1)

Once the sources, emissions, and control methods have all been selected, the cost of compliance is estimated. The cost of compliance, expressed in units of dollars per ton of pollutant controlled ($/ton), describes the cost associated with the reduction of visibility-impairing pollutants. Specific costs associated with operation, maintenance, and utilities at the facility are presented in Table 3-1 (attached).

The Federal Guidance Document recommends that cost estimates follow the methods and recommendations in the Control Cost Manual. This includes the recently updated calculation spreadsheets that implement the revised chapters of the Control Cost Manual. The Federal Guidance Document recommends using the generic cost estimation algorithms detailed in the Control Cost Manual in cases where site-specific cost estimates are not available.

Additionally, the Federal Guidance Document recommends using the Control Cost Manual in order to effect an "apples-to-apples" comparison of costs across different sources and industries.

3.4 Step 4: Characterizing the Time Necessary for Compliance (Statutory Factor 2)

Characterizing the time necessary for compliance requires an understanding of construction timelines, which include planning, construction, shake-down and, finally, operation. The time that is needed to complete these tasks must be reasonable and does not have to be "as expeditiously as practicable…" as is required by the Best Available Retrofit Technology regulations.

3.5 Step 5: Characterize Energy and non-Air Environmental Impacts (Statutory Factor 3)

Both the energy impacts and the non-air environmental impacts are estimated for the control measures that were costed in Step 3. These include estimating the energy required for a given control method, but do not include the indirect impacts of a particular control method, as stated in the Federal Guidance Document.

The non-air environmental impacts can include estimates of waste generated from a control measure and its disposal. For example, nearby water bodies could be impacted by the disposed-of waste, constituting a non-air environmental impact.

3.6 Step 6: Characterize Remaining Useful Life of Source (Statutory Factor 4)

The Federal Guidance Document highlights several factors to consider when characterizing the remaining useful life of the source. The primary issue is that often the useful life of the control measure is shorter than the remaining useful life of the source. However, it is also possible that a source is slated to be shut down well before a control device would be cost effective.

4 PM10 ANALYSIS

The Analysis for PM_{10} emissions follows the six steps previously described in Section 3.

4.1 Step 1 – Determine PM_{10} Control Measures for Consideration

4.1.1 Baghouse

Baghouses, or fabric filters, are common in the wood products industry. In a fabric filter, flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to collect on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are one of the most common forms of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. The accumulated particles are periodically removed from the filter surface by a variety of mechanisms and are collected in a hopper for final disposition.

Typical new equipment design efficiencies are between 99 and 99.9 percent. Several factors determine fabric filter collection efficiency. These include gas filtration velocity, particle characteristics, fabric characteristics, and the cleaning mechanism. In general, collection efficiency increases with decreasing filtration velocity and increasing particle size. Fabric filters are generally less expensive than electrostatic precipitators (ESPs) and they do not require complicated control systems. However, fabric filters are subject to plugging for certain exhaust streams and do require maintenance and inspection to ensure that plugging or holes in the fabric have not developed. Regular replacement of the filters is required, resulting in higher maintenance and operating costs.

Certain process limitations can affect the operation of baghouses in some applications. For example, exhaust streams with very high temperatures (i.e., greater than 500 degrees Fahrenheit [°F]) may require specially formulated filter materials and/or render baghouse control infeasible. Additional challenges include the particle characteristics, such as materials that are "sticky" and tend to impede the removal of material from the filter surface. Exhaust gases that exhibit corrosive characteristics may also impose limitations on the effectiveness of baghouses. In wood products applications it is expected that particle characteristics, specifically particle and exhaust moisture content, may limit the feasibility on implementation. However, for some sources, baghouses are considered technically feasible.

4.1.2 Wet Venturi Scrubber

Wet scrubbers remove particulate from gas streams primarily by inertial impaction of the particulate onto a water droplet. In a venturi scrubber, the gas is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity, causing the water to shear into fine droplets. Particles in the gas stream then impact the water droplets. The entrained water droplets are subsequently removed from the gas stream by a cyclonic separator. Venturi scrubber control efficiency increases with increasing pressure drops for a given particle size. Control efficiency increases with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Control efficiencies are typically around 90 percent for particles with a diameter of 2.5 microns or larger.

Although wet scrubbers mitigate air pollution concerns, they also generate a water pollution concern. The effluent wastewater and wet sludge stream created by wet scrubbers requires that the operating facility have a water treatment system and subsequent disposal system in place. These consequential systems increase the overall cost of wet scrubbers and cause important environmental impacts to consider.

The facility operates a closed-loop wastewater system for its existing process water, stormwater and sanitary water. The system currently operates at maximum capacity for the management of wastewater and wet sludge and is unable to accommodate any additional wastewater streams. Additionally, since there are no municipal water treatment plants approved to accept industrial wastewater effluents, there are no off-site options for wastewater management. Therefore, wet control technologies are considered infeasible for the facility and will not be evaluated further in the Analysis.

4.1.3 Electrostatic Precipitator

ESPs are used extensively for control of PM emissions. An ESP is a particulate control device that uses electrical force to move particles entrained with a gas stream onto collection surfaces. An electrical charge is imparted on the entrained particles as they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the corona that charges the particles, thereby allowing for their collection on the oppositely charged collector walls. In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. Instead of the collection hoppers used by dry ESPs, wet ESPs utilize a drainage system and water treatment of some sort. In dry ESPs, the collectors are knocked, or "rapped," by various mechanical means to dislodge the collected particles, which slide downward into a hopper for collection.

Typical control efficiencies for new installations are between 99 and 99.9 percent. Older existing equipment has a range of actual operating efficiencies of 90 to 99.9 percent. While several factors determine ESP control efficiency, ESP size is the most important because it determines the exhaust residence time; the longer a particle spends in the ESP, the greater the chance of collecting it. Maximizing electric field strength will maximize ESP control efficiency. Control efficiency is also affected to some extent by particle resistivity, gas temperature, chemical composition (of the particle and gas), and particle size distribution.

Similar to wet scrubber control systems, wet ESPs also create a water pollution concern as they reduce air pollution. Use of wet ESPs generates a wastewater and wet sludge effluent that requires treatment and subsequent disposal. As noted in Section 4.1.2, the wastewater system at the facility currently operates at maximum capacity and is unable to accommodate any additional wastewater streams. Therefore, wet ESPs are considered infeasible for the facility and will not be evaluated further in the Analysis.

The use of dry ESPs with suspended particulates is a safety hazard as the particulate dust may explode if exposed to an ignition source such as spark between the charged ESP plates. Thus, based on the low moisture content of the exhaust streams, and the facility's concerns regarding potential fire or explosion hazards, dry ESPs are considered infeasible for the facility and will not be evaluated further in the Analysis.

4.2 Step 2 – Selection of Emissions

See Section 2.1 for descriptions of the PM_{10} emission units and emission rates selected for the Analysis.

4.3 Step 3 – Characterizing the Cost of Compliance

Table 4-2 (attached) presents the detailed cost analyses of the technically feasible PM_{10} control technologies included in the Analysis. A summary of the cost of compliance, expressed in $/ton, is shown below in Table 4-1:

Table 4-1
Cost of Compliance Summary for PM_{10}

Emissions Unit	Emissions Unit ID	Cost of Compliance ($/ton)
		Baghouse
Particleboard Press and Unloader	PB01	36,664
Trim Saw Vent	PB03	24,639
Cyclone PB24	PB08	24,763
Bake Oven Roof Vent	HB09	26,985
Cyclone HB7	HB10	25,942
Cyclone HB23	HB14	25,782
Cyclone HB27	HB15	49,642

4.4 Step 4 – Characterizing the Time Necessary for Compliance

Several steps will be required before the control device is installed and fully operational. After selection of a control technology, all of the following will be required: permitting, equipment procurement, construction, startup and a reasonable shakedown period, and verification testing. It is anticipated that it will take up to 18 months to achieve compliance.

4.5 Step 5 – Characterizing the Energy and non-Air Environmental Impacts

4.5.1 Energy Impacts

Energy impacts can include electricity and/or supplemental fuel used by a control device. Electricity use can be substantial for large projects if the control device uses large fans, pumps, or motors. Baghouse control systems require significant electricity use to operate the powerful fans required to overcome the pressure drop across the filter bags. Dry ESPs are expected to require even more electricity than baghouses, since high-voltage electricity is required for particle collection and removal. Dry ESPs also require powerful fans to maintain exhaust flow through the system. Similarly, wet venturi scrubbers and wet ESPs will use significant amounts of electricity to power large pumps used to supply water for the control device and the subsequent treatment process.

4.5.2 Environmental Impacts

Expected environmental impacts for baghouses and dry ESPs include the management of materials collected by the control devices. For sources where this material is clean wood residuals, it may be possible to reuse the material in the production process. However, collected materials that are degraded or that contain potential contaminants would be considered waste materials requiring disposal at a landfill.

As mentioned above, wet venturi scrubbers and wet ESPs generate liquid waste streams, creating a water pollution issue. The effluent of wastewater and wet sludge generated by both control technologies will require the facility to have in place an appropriately sized water treatment system and subsequent waste disposal system and/or procedure. These systems increase the overall cost of installation and cause important environmental impacts to consider.

While none of the control technologies evaluated in the PM_{10} Analysis would require the direct consumption of fossil fuels, another, less quantifiable, impact from energy use may result from producing the electricity (i.e., increased greenhouse gases and other pollutant emissions). In addition, where fossil fuels are used for electricity production, additional impacts are incurred from the mining/drilling and use of fossil fuels for combustion.

4.6 Step 6 – Characterize the Remaining Useful Life

It is anticipated that the remaining life of the emissions units, as outlined in the Analysis, will be longer than the useful life of the technically feasible control systems. No emissions units are subject to an enforceable requirement to cease operation. Therefore, in accordance with the Federal Guidance Document, the presumption is that the control system would be replaced by a like system at the end of its useful life. Thus, annualized costs in the Analysis are based on the useful life of the control system rather than the useful life of the emissions units.

5 SO_2 ANALYSIS

SO_2 emissions from the plant are negligible. Given the reductions for a small source likely would not improve visibility and would not be cost effective, these activities will not be evaluated further in the Analysis.

6 NO_X ANALYSIS

Because of the limited combustion sources at the facility, the Title V permit contains a generic PSEL for NOx of 39 tons/year. Actual emissions are substantially lower (6.9 tons in 2019). Given that the reductions for small sources likely would not improve visibility and would not be cost effective, these activities will not be evaluated further in the Analysis.

7 CONCLUSION

This report presents cost estimates associated with installing control devices at the Klamath Falls facility in order to reduce visibility-impairing pollutants in Class I areas and provides the Four Factor Analysis conducted consistent with available DEQ and USEPA guidance documents. Collins believes that the above information meets the state objectives and is satisfactory for the DEQ's continued development of the SIP as a part of the Regional Haze program.

Based on the costs described above for the controls under consideration, there does not appear to be any control device that, on a dollar per ton of pollutant-controlled basis, would be considered cost effective. In addition, given the extensive pollution controls already in place at the facility, any additional controls would result in limited visibility improvement. In the absence of significant visibility improvement, it would not be appropriate to require investment in additional controls at a wood products facility in an economically challenged part of the state.

LIMITATIONS

The services undertaken in completing this report were performed consistent with generally accepted professional consulting principles and practices. No other warranty, express or implied, is made. These services were performed consistent with our agreement with our client. This report is solely for the use and information of our client unless otherwise noted. Any reliance on this report by a third party is at such party's sole risk.

Opinions and recommendations contained in this report apply to conditions existing when services were performed and are intended only for the client, purposes, locations, time frames, and project parameters indicated. We are not responsible for the impacts of any changes in environmental standards, practices, or regulations subsequent to performance of services. We do not warrant the accuracy of information supplied by others, or the use of segregated portions of this report.

TABLES

Table 2-1
PM_{10} Evaluation for Regional Haze Four Factor Analysis
Collins Products, LLC. - Klamath Falls, Oregon

Emission Units (1)	Emission Unit ID(s)	Current PM_{10} Control Technology (1)	Pollution Control Device ID	Annual PM_{10} Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Evaluation	Emission Controls To Be Evaluated
Defibrators/Dryer (x 3)	HB01-HB03	Cyclone, Biofilter	HB50 (Biofilter)	33.5	No	Sources are already controlled. Process exhaust is routed to individual cyclones, followed by in-duct water sprays, followed by a biofilter.	--
Core Dryers	PB05	Baghouses	PB3, PB4	30.6	No	Sources are already equipped with best-in-class controls. Process exhaust from the core dryers is routed to two downstream baghouses (PB3 and PB4).	--
Particleboard Press and Unloader Area	PB01	Biofilter	PB45	16.1	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Trim Saw Vent	PB03	--	--	11.9	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Cyclone PB24	PB08	--	--	11.1	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Bake Oven Roof Vents	HB09	--	--	10.8	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Cyclone HB7	HB10	--	--	8.66	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Cyclone HB23	HB14	--	--	8.71	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Cyclone HB27	HB15	--	--	4.52	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Cyclones w/ Secondary Filters	PB10	Bagfilters	PB35, PB36, PB37	2.98	No	Sources already are equipped with best in class controls.	--
Surface Dryers	PB06	Baghouse	PB44	2.54	No	Sources already are equipped with best in class controls.	--
All Other Emission Units	Varies	Varies per Emission Unit	--	13.4 (3)	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

NOTES:

PM_{10} = Particulate matter with an aerodynamic diameter of 10 microns or less.

REFERENCES:

(1) Information from the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.

(2) Information from the Review Report for the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.

(3) The annual PM_{10} emissions estimate of 13.4 tons per year represents the sum total of annual PM_{10} emissions from all emission units collectively comprising less than 10% of the total facility PM_{10} emissions rate. The maximum annual PM_{10} emissions estimate, from a single emissions unit within this grouping, is only 2.44 tons per year.

Table 2-2
SO_2 Evaluation for Regional Haze Four Factor Analysis
Collins Products, LLC. - Klamath Falls, Oregon

Emission Units (1)	Emission Unit ID(s)	Current SO_2 Control Technology (1)	Annual SO_2 Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Evaluation	Emission Controls To Be Evaluated
Aggregate Insignificant Activities	Varies	--	1.00	No	Emission controls for 1 ton/yr would not improve visibility and would not be cost effective.	--
Core Dryers	PB05	--	0.50	No	PB Core Dryers no longer have the ability to burn fuel oil and only have the potential to emit 0.5 tons/yr of SO_2 when burning natural gas. Emission controls would not improve visibility and would not be cost effective.	--
All Other Emission Units	Varies	--	0.046	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

NOTES:

SO_x = Sulfur dioxide

REFERENCES:

(1) Information from the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.

(2) Information from the Review Report for the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.

Table 2-3
NO_X Evaluation for Regional Haze Four Factor Analysis
Collins Products, LLC. - Klamath Falls, Oregon

Emission Units (1)	Emission Unit ID(s)	Current NO_X Control Technology (1)	Annual NO_X Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Evaluation	Emission Controls To Be Evaluated
Core Dryers	PB05	--	8.88	No	PB Core Dryers no longer have the ability to burn fuel oil and only have the potential to emit 8.88 tons/yr of NO_x when burning natural gas. Emission controls would not improve visibility and would not be cost effective.	--
Hardboard Coating Ovens	HB17	--	6.90	Yes	Emission controls would not improve visibility and would not be cost effective.	--
Bake Oven	HB08	--	3.52	Yes	Emission controls would not improve visibility and would not be cost effective.	--
All Other Emission Units	Aggregate Insignificant	--	1.00	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

NOTES:
NO_x = Oxides of nitrogen

REFERENCES:
(1) Information from the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.
(2) Information from the Review Report for the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.

Table 2-4
Emissions Unit Input Assumptions and Exhaust Parameters
Collins Products, LLC. - Klamath Falls, Oregon

Emissions Unit ID	Emissions Unit Description	Control Evaluation Proposed? (Yes/No)			Heat Input Capacity (MMBtu/hr)	Exhaust Parameters		
						Exit Temperature (°F)	Exit Flowrate	
		PM$_{10}$	NO$_X$	SO$_2$			(acfm) (1)	(scfm)
HB01 - HB03	Defibrators/Dryers	Yes	No	No	--	199 (1)	56,208	39,029 (a)
HB08	Bake Oven	No	Yes	No	10.6 (1)	271 (1)	28,879	18,056 (1)
HB09	Bake Oven Roof Vents	Yes	No	No	--	70.6 (1)	19,364	16,712 (1)
HB10	Cyclone HB7	Yes	No	No	--	70 (2)	5,827	5,031 (a)
HB14	Cyclone HB23	Yes	No	No	--	70 (2)	5,827	5,031 (a)
HB15	Cyclone HB27	Yes	No	No	--	70 (2)	5,827	5,031 (a)
HB17	Hardboard Coating Ovens	No	Yes	No	38.6 (1)	271 (1)	28,879	18,083 (a)
PB01	Particleboard Press and Unloader Area	Yes	No	No	--	77.7 (1)	78,862	67,165 (1)
PB03	Trim Saw Vent	Yes	No	No	--	220 (1)	19,364	13,027 (a)
PB05	Core Dryers	No	No	No	20.7 (3)	141 (1)	15,160	10,641 (1)
PB08	Cyclone PB24	Yes	No	No	--	70 (2)	15,970	13,788 (a)

NOTES:

acfm = actual cubic feet per minute.

°F = degree fahrenheit

ft/sec = feet per second.

MMBtu/hr = million British thermal units per hour.

NO$_x$ = Oxides of nitrogen

PM$_{10}$ = Particulate matter with an aerodynamic diameter of 10 micron or less

scfm = standard cubic feet per minute.

SO$_x$ = Sulfur dioxide

(a) Exit flowrate (scfm) = (exit flowrate [acfm]) x (1 - [6.73E-06] x [facility elevation above sea level {ft}])$^{5.258}$ x (530) / (460 + [exit temperature {°F}])

Facility elevation above sea level (ft) = 4,094 (4)

REFERENCES:

(1) Data provided by Collins Products, LLC.

(2) Assumes an ambient temperature of 70°F.

(3) Information from the Review Report for the Title V Operating Permit no. 18-0013-TV-01 issued January 6, 2015 by the Oregon DEQ.

(4) Elevation above sea level obtained from publicly available online references.

Table 3-1

Operating and Maintenance Rates

Collins Products, LLC. - Klamath Falls, Oregon

Parameter	Value (units)		
FACILITY OPERATIONS			
Annual Hours of Operation	8,760	(hrs/yr)	(1)
Annual Days of Operation	365	(day/yr)	(1)
Daily Hours of Operation	24.0	(hrs/day)	(1)
UTILITY COSTS			
Electricity Rate	0.064	($/kWh)	(2)
Natural Gas Rate	5.22	($/MMBtu)	(2)
Water Rate	10.0	($/Mgal)	(2)
Compressed Air Rate	0.004	($/Mscf)	(2)
Landfill Disposal Fee	74.0	($/ton)	(2)
LABOR COSTS			
Maintenance Labor Rate	25.18	($/hr)	(2)
Operating Labor Rate	18.63	($/hr)	(2)
Supervisory Labor Rate	35.00	($/hr)	(2)
Typical Shifts per Day	3.00	(shifts/day)	(2)

NOTES:

Mgal = thousand gallons.

MW-hr = megawatt-hour.

scf = standard cubic feet.

REFERENCES:

(1) Assumes continuous annual operation.

(2) Data provided by Collins Products, LLC.

Table 4-2

Cost Effectiveness Derivation for Baghouse Installation

Collins Products, LLC. - Klamath Falls, Oregon

Emissions Unit ID	Emissions Unit Description	Input Parameters		Pollutant Removed by Control Device $^{(a)}$ (tons/yr)	Operating Parameter	
		Exhaust Flowrate $^{(1)}$ (acfm)	PM$_{10}$ Annual Emissions Estimate $^{(2)}$ (tons/yr)		Electrical Requirements $^{(3)}$ (kW)	Number of Filter Bags Required $^{(4)}$
HB09	Bake Oven Roof Vents	19,364	10.8	10.7	88.7	250
HB10	Cyclone HB7	5,827	8.66	8.57	39.5	82
HB14	Cyclone HB23	5,827	8.71	8.63	39.5	82
HB15	Cyclone HB27	5,827	4.52	4.47	39.5	82
PB01	Particleboard Press and Unloader Area	78,862	16.1	15.9	306.5	987
PB03	Trim Saw Vent	19,364	11.9	11.7	88.7	250
PB08	Cyclone PB24	15,970	11.1	11.0	76.8	208

Emissions Unit ID	Emissions Unit Description	Direct Costs			Total Indirect Costs $^{(d)}$	Total Capital Investment $^{(e)}$	Capital Recovery Cost				Direct Annual Costs								Total Indirect Annual Costs $^{(o)}$	Total Annual Cost $^{(p)}$	Annual Cost Effectiveness $^{(q)}$
		Purchased Equipment Cost		Total Direct Cost $^{(c)}$			Control Device $^{(f)}$	Replacement Parts			Operating Labor		Maintenance		Utilities			Total Direct Annual Costs $^{(14)}$			
		Basic Equip./Services Cost $^{(4)}$	Total $^{(b)}$					Filter Bag Cost $^{(4)}$	Bag Labor Cost $^{(h)}$	Filter Bag $^{(i)}$	Operator Cost $^{(j)}$	Supervisor Cost $^{(k)}$	Labor Cost $^{(j)}$	Material Cost $^{(14)}$	Electricity Cost $^{(l)}$	Compressed Air Cost $^{(m)}$	Landfill Cost $^{(n)}$				
USEPA COST MANUAL VARIABLE		**A**	**B**	**DC**	**IC**	**TCI**	**CRC$_D$**	**C$_B$**	**C$_L$**	**CFC$_B$**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**DAC**	**IAC**	**TAC**	**($/ton)**
HB09	Bake Oven Roof Vents	$106,809	$126,034	$219,300	$56,715	**$276,015**	$21,681	$3,763	$1,574	$1,581	$40,800	$6,120	$27,572	$27,572	$50,053	$40,711	$793	$195,202	$72,279	**$289,162**	**$26,985**
HB10	Cyclone HB7	$76,367	$90,113	$156,796	$40,551	**$197,347**	$15,502	$1,233	$516	$518	$40,800	$6,120	$27,572	$27,572	$22,293	$12,251	$634	$137,760	$69,132	**$222,394**	**$25,942**
HB14	Cyclone HB23	$76,367	$90,113	$156,796	$40,551	**$197,347**	$15,502	$1,233	$516	$518	$40,800	$6,120	$27,572	$27,572	$22,293	$12,251	$638	$137,764	$69,132	**$222,398**	**$25,782**
HB15	Cyclone HB27	$76,367	$90,113	$156,796	$40,551	**$197,347**	$15,502	$1,233	$516	$518	$40,800	$6,120	$27,572	$27,572	$22,293	$12,251	$331	$137,456	$69,132	**$222,090**	**$49,642**
PB01	Particleboard Press and Unloader Area	$240,608	$283,917	$494,016	$127,763	**$621,779**	$48,841	$14,883	$6,213	$6,249	$40,800	$6,120	$27,572	$27,572	$172,874	$165,799	$1,177	$448,163	$86,109	**$583,113**	**$36,664**
PB03	Trim Saw Vent	$106,809	$126,034	$219,300	$56,715	**$276,015**	$21,681	$3,763	$1,574	$1,581	$40,800	$6,120	$27,572	$27,572	$50,053	$40,711	$869	$195,278	$72,279	**$289,238**	**$24,639**
PB08	Cyclone PB24	$99,176	$117,028	$203,629	$52,663	**$256,292**	$20,132	$3,129	$1,309	$1,315	$40,800	$6,120	$27,572	$27,572	$43,324	$33,575	$815	$181,092	$71,490	**$272,714**	**$24,763**

Table 4-2
Cost Effectiveness Derivation for Baghouse Installation
Collins Products, LLC. - Klamath Falls, Oregon

NOTES:

(a) Pollutant removed by control device (tons/yr) = (PM_{10} annual emissions estimate [tons/yr]) x (baghouse control efficiency [%] / 100)

Baghouse control efficiency (%) = 99.0 (4)

(b) Total purchased equipment cost ($) = (1.18) x (basic equipment/services cost [$]); see reference (5).

(c) Total direct cost ($) = (1.74) x (total purchased equipment cost [$]) + (site preparation cost, SP [$]) + (building cost, Bldg. [$]); see reference (5).

Site preparation cost, SP ($) = 0 (6)
Building cost, Bldg. ($) = 0 (6)

(d) Total indirect cost ($) = (0.45) x (total purchased equipment cost [$]); see reference (5).

(e) Total capital investment ($) = (total direct cost [$]) + (total indirect cost [$]); see reference (5).

(f) Control device capital recovery cost ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (7)

Control device capital recovery factor = 0.0786 (g)

(g) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs}] - 1); see reference (8).

Interest rate (%) = 4.75 (9)
Baghouse economic life (yr) = 20 (10)
Filter bag economic life (yr) = 4 (4)

(h) Bag replacement labor cost ($) = (total time required to change one bag [min/bag]) x (hr/60 min) x (number of filter bags required [bags]) x (maintenance labor rate [$/hr])

total time required to change one bag (min/bag) = 15 (12)
Maintenance labor rate ($/hr) = 25.18 (13)

(i) Filter bag capital recovery cost ($) = ([initial filter bag cost {$}] x (1.08) + [bag replacement labor cost {$}]) x (filter bag capital recovery factor); see reference (13).

Filter bag capital recovery factor = 0.2804 (g)

(j) Operator or maintenance labor cost ($) = (operator or maintenance hours per shift [hrs/shift]) x (operating shifts per day [shifts/day]) x (annual days of operation [days/yr]) x (operator or maintenance labor rate [$/hr])

Operating labor hours per shift [hrs/shift] = 2 (13)
Maintenance labor hours per shift [hrs/shift] = 1 (13)
Shifts per day (shifts/day) = 3 (13)
Annual days of operation (days/yr) = 365 (13)
Operator labor rate ($/hr) = 18.63 (13)
Maintenance labor rate ($/hr) = 25.18 (13)

(k) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (13).

(l) Annual electricity cost ($) = (electricity rate [$/kWh]) x (total power requirement [kWh]) x (annual hours of operation [hrs/yr])

Electricity rate ($/kWh) = 0.064 (13)
Annual hours of operation (hrs/yr) = 8,760 (13)

(m) Annual compressed air cost ($) = (compressed air cost [$/Mscf]) x (Mscf/1,000 scf) x (exhaust flowrate [acfm]) x (60 min/hr) x (annual hours of operation [hrs/yr])

Compressed air cost ($/Mscf) = 0.0040 (13)
Annual hours of operation (hrs/yr) = 8,760 (13)

(n) Annual landfill cost ($) = (landfill disposal rate [$/ton]) x (pollutant removed by control device [tons/yr])

Landfill disposal rate ($/ton) = 74.00 (13)

(o) Total indirect annual cost ($) = (0.60) x ([operator cost {$}] + [superviser cost {$}] + [maintenance cost {$}] + [maintenance material cost {$}]) + (0.04) x (total capital investment [$]); see reference (13).

(p) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$]) + (control device capital recovery cost [$])

(q) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.

(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.

(3) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. In the quote, costs and equipment requirements for three differently sized baghouses (5,000 cfm, 20,000 cfm, and 50,000 cfm) are presented. For the smallest exhaust flowrate above (MC4), these quoted data was scaled using a ratio. All other costs/data were scaled and obtained using tread line formulas. It is important to note that the quoted costs do not include the costs associated with taxes, installation of equipment, all concrete work (excavation, engineering, plumbing, electrical), building/foundation upgrades, and permitting or licensing.

(4) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-025) for baghouse (fabric filter), pulse-jet cleaned type issued July 15, 2003. Assumes minimum typical new equipment design efficiency.

(5) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See Table 1.9 "Capital Cost Factors for Fabric Filters." The 1.18 factor includes instrumentation, sales tax, and freight.

(6) Conservatively assumes no costs associated with site preparation or building requirements.

(7) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.

(8) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.

(9) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.

(10) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.2.

(11) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. Typical bag filter life is 4 years.

(12) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.1.4.

(13) See Table 3-1, Utility and Labor Rates.

(14) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.

REGIONAL HAZE – FOUR FACTOR ANALYSIS

Columbia Forest Products
Klamath Falls, Oregon

June 2020

Regional Haze – Four Factor Analysis

Prepared for:
Columbia Forest Products
4949 Highway 97
Klamath Falls, Oregon 97603

This document has been prepared by SLR International Corporation (SLR). The material and data in this report were prepared under the supervision and direction of the undersigned.

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CONTENTS

ATTACHMENTS

Attachment A	Cost Analysis
Attachment B	Supporting Documents

ACRONYMS, ABBREVIATIONS AND TERMS

4FA	Four Factor Analysis
BACT	Best Available Control Technology
Btu	British thermal unit
CFP	Columbia Forest Products
CFR	Code of Federal Regulations
CO_2	Carbon dioxide
DEQ	Department of Environmental Quality
EPA	Environmental Protection Agency
ESP	Electrostatic precipitator
FGR	Fuel gas recirculation
GHG	Greenhouse gas
HAP	Hazardous air pollutants
IMPROVE	Interagency Monitoring of Protected Visual Environments
LAER	Lowest Achievable Emission Rate
LNB	Low NO_X burner
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_X	Nitrogen Oxides
NSR	New Source Review
OFA	Overfire air
O&M	Operation and maintenance
PM	Particulate Matter
PM_{10}	Coarse Particle Matter or Particulate Matter; with an aerodynamic diameter of 10 microns or less
PSEL	Plant Site Emission Limit
RACT	Reasonably Available Control Technology
RBLC	RACT/BACT/LAER Clearinghouse
SCR	Selective Catalytic Reduction
SNCR	Selective Non-catalytic Reduction
SO_2	Sulfur Dioxide
tpy	Tons per year

1. INTRODUCTION

This Regional Haze Four Factor Analysis (4FA) was prepared on behalf of Columbia Forest Products Klamath Falls (the Facility) located at 4949 Highway 97 South, Klamath Falls, Oregon. The Facility manufactures plywood under Title V operating permit number 18-0014-TV-01. The Oregon Department of Environmental Quality (DEQ) identified the Facility as a significant source of regional haze precursor emissions to a Class I area in Oregon, thus triggering the need for a 4FA under the regional haze program.

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.

Data from the Environmental Protection Agency (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 less than 10-micron in diameter (PM_{10}).

The nearest Class I areas to the Facility are the Mountain Lakes Wilderness, located 13 miles northwest, and Crater Lake National Park, located about 40 miles north.

This 4FA provides a detailed evaluation of the Facility emission units that contribute emissions of precursor compounds. The purpose of the analysis is to determine whether additional specific control measures are reasonable for the control of precursor compounds. The four factors considered in this analysis 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.

1.1 FACILITY OVERVIEW

The Facility is a hardwood and veneer plywood mill (NAICS codes 321211 and 221330) located just south of the City of Klamath Falls, Oregon, along the northwest bank of the Klamath River. The Facility operates under Title V operating permit number 18-0014-TV-01 issued by the Oregon DEQ on September 26, 2017 and which expires on October 1, 2022.

The Facility is required to have a Title V air operating permit because it has potential to emit more than 100 tons per year of a criteria pollutant. The Facility has taken a synthetic minor permit limit to limit their potential to emit hazardous air pollutants (HAP) to less than the major HAP source levels.

The main product of the plant is 4’ x 8’ x 3/4” thick hardwood faced panels. The hardwood veneer is brought in from other locations in a pre-dried condition. Most of the core panels consist of plywood manufactured from white fir veneer which is processed from the raw logs in the Facility. Some of the core panels to which the hardwood face veneer is glued are brought in from elsewhere and consist of veneer core or composite panels (e.g., medium density fiberboard) manufactured by other companies.

The raw logs are brought in by truck and stored until needed. The raw logs are then debarked in a ring de-barker. After the de-barker, the logs are cut to length by a set of large circular chop saws. These sections of peeler logs, called blocks, are transported by conveyor and automatically sorted into bins. The waste trim pieces of the logs known as lily pads are transported to the lily pad chipper. Front end loaders place the blocks into the vats (steam conditioning chests). The blocks are conditioned with hot water and steam to make them suitable for turning on a lathe to peel off veneer.

After conditioning, the blocks are placed on the in-feed conveyors to the lathe. At the lathe, the veneer ribbon travels down a conveyor, through a clipping station where defects are clipped out and to an automatic stacker which sorts the veneer pieces by size and moisture content. Veneer pieces are also pulled from the line after the stacker at the green chain. Reject pieces of veneer and trim pieces are carried by conveyor to the veneer chipper. The block cores left over after peeling are conveyed to the sorter. Some are stockpiled to be trucked offsite and sold while others are chipped for fuel.

The stacks of green veneer are transported by forklift to the B plant. The green veneer is dried in one of the two dryers to less than 24% moisture content. Veneer pieces which test out above the moisture specification after exiting the dryers are either re-dried or stored until they meet the required dryness specification. The two dryers are the Keller #1 & #2 (fired by natural gas).

The dried veneer is worked into solid sheets with a minimum of voids by plugging defects or edge gluing smaller pieces with hot melt glue.

The next activity in the plywood manufacturing process is that of spreading the glue on the veneer sheets, orienting the grain direction of the core veneers at right angles to each other, then placing the hardwood face veneers at the top and bottom of each assembly. After gluing, the stack of laid-up panels is initially placed in a cold press, then put into one of three hot presses.

The plywood panels exiting hot presses are moved to the panel saw for trimming. Any voids in the faces are filled with putty by hand in the patch line. Some oak faced panels are conditioned to prevent staining.

After the patch line, the panels are run through the sander, then inspected and packaged for shipment. The sander is ventilated by a separate sander dust ventilation system. Some of the panels have a coating applied in a UV coating line.

The byproducts or “residuals” are handled as four separate material streams: Wood chips, hogged fuel (mostly bark), plytrim, and sander dust. These residual streams are transported by such means as mechanical conveyor, truck load out bin, and pneumatic transfer through cyclones (C1 & C2). Steam for the presses and the vats is provided by the north and south boilers.

1.2 NESHAPs

The Facility boilers are subject to 40 CPR Part 63, Subpart JJJJJJ, *National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers Area Sources*. The boilers are subject to two work practice requirements: conduct a one-time energy assessment and conduct a boiler tune-up every 2 years.

The Wood Building Products (surface coating) NESHAP (40 CFR, Part 63, Subpart QQQQ) that was promulgated on May 28, 2003 is applicable to the UV coating line.

In 2007, the Facility demonstrated that it is no longer a major source of HAPs, so the NESHAPs for Plywood and Composite Wood Products (40 CFR, Part 63, Subpart DDDD) and Industrial, Commercial and Institutional Boilers and Process Heaters (40 CFR, Part 63, Subpart DDDDD) at major sources are not applicable.

1.3 PRECURSOR COMPOUND EMISSIONS

The Facility emits three types of regional haze precursor compounds: nitrogen oxides, sulfur dioxide, and particulate matter less than 10 microns in diameter. Facility-wide emissions of these compounds for 2017 and the Facility's potential to emit for each compound are presented in Table 1-1. Detailed emission calculations are provided in Attachment B.

Table 1-1. Actual and Permitted Facility-wide Emissions for CFP Klamath Falls

Emission Unit	**2017 Actual Emissions (tons per year)**				**Permitted Emissions (tons per year)**			
	NO_X	**SO_2**	**PM_{10}**	**Total Quantity**	**NO_X**	**SO_2**	**PM_{10}**	**Total Quantity**
South Boiler	37.59	1.01	36.18	74.78	45.55	1.23	43.84	90.62
North Boiler	0.0	0.0	0.0	0.0	6.48	0.25	5.28	12.01
Veneer Dryers	5.03	--	15.09	20.12	9.75	--	29.26	39.01
Plywood Press	--	--	2.29	2.29	--	--	3.26	3.26
Storage Pile	--	--	1.72	1.72	--	--	2.44	2.44
Material Handling	--	--	1.92	1.92	--	--	2.73	2.73
Facility Wide	**43.18**	**1.02**	**57.71**	**101.91**	**65.0**	**39.0***	**87.0**	**191.0**

*Generic Plant Site Emission Limit (PSEL)

The two boilers, two veneer dryers, three press vents, a hog-fuel storage pile, and material handling equipment emit precursor compounds. The precursor compound emissions from each emission unit and the existing pollution control equipment are summarized in Table 1-2.

Table 1-2. Summary of Precursor Compounds Emitted by Emission Unit

Emission Unit	Emission Unit ID	Precursor Compounds Emitted	Installation Date	Existing Pollution Control Equipment
North Boiler	BLR-N	PM_{10}, SO_2, NO_X	1939	NA
South Boiler	BLR-S	PM_{10}, SO_2, NO_X	1944	Multiclone
Keller Dryer #1 (east)	V-N	PM_{10}, SO_2, NO_X	1984	NA
Keller Dryer #2 (west)	V-N	PM_{10}, SO_2, NO_X	1989	NA
Press Vent 1	PV-1	PM_{10}	1983	NA
Press Vent 2	PV-2	PM_{10}	Before 1978	NA
Press Vent 3	PV-3	PM_{10}	Before 1978	NA
Storage Piles	SP	PM_{10}	NA	NA
Material Handling	MH	PM_{10}	NA	Cyclone, Baghouse

The emissions of two boilers, two veneer dryers, and three press vents comprise 98.7% of NO_X, 99% of SO_2, 93% of PM_{10} emissions compared to 2017 facility-wide emissions. Therefore, only these emission units are included in this analysis and are presented in the following sections. Since the 2017 actual emissions of SO_2 are very low (1.02 tons per year [tpy]), SO_2 emissions are not reviewed further in this analysis.

1.3.1 NORTH AND SOUTH BOILERS

The North and South Boilers are capable of firing wood or bark. The South Boiler is a C & E Dutch oven boiler with a rated steam capacity of 35,000 pounds per hour (lb/hr). The South Boiler was installed in 1944. Particulate emissions are controlled by a multiclone installed in 1994.

The North Boiler is an E.F. Huffman Dutch oven boiler with a rated steam capacity of 12,500 lb/hr. The North Boiler was installed in 1939. Particulate emissions are uncontrolled. The North Boiler is currently not operating.

The 2017 annual emissions from these boilers are presented in Table 1-3.

Table 1-3. 2017 Annual Emissions – Boilers

Emission Unit	NO_X Emissions (tons/yr)	PM_{10} Emissions (tons/yr)	SO_2 Emissions (tons/yr)
North Boiler (BLR-N)	0.0	0.0	0.0
South Boiler (BLR-S)	37.59	36.18	1.01

1.3.2 VENEER DRYERS (V-N)

The Facility operates two veneer dryers. The primary species of wood dried are White Fir, Pine, and Douglas Fir. Dryer particulate emissions are uncontrolled.

Dryer 1 (east dryer) was manufactured by Keller. It is a four deck, three zone jet tube dryer heated by burning natural gas. The maximum throughput is 13,000 ft^2/hr on a 3/8” basis. The maximum heating capacity of the burners associated with the dryer is 36 MMBtu/hr. The dryer was installed in 1984.

Dryer 2 (west dryer) was also manufactured by Keller. It is a four deck, three zone jet tube dryer heated by burning natural gas. The maximum throughput as-installed was 9,000 ft^2/hr on a 3/8” basis. The dryer was installed in 1989 and was modified in 2005 by adding another zone to increase the capacity to that of Dryer 1. The current capacity of Dryer 2 is 13,000 ft^2/hr on a 3/8” basis. The maximum heating capacity of the burners associated with the dryer is 41 MMBtu/hr.

The 2017 total annual emissions from both of the dryers are presented in Table 1-4.

Table 1-4. 2017 Annual Emissions – Veneer Dryers

Emission Unit	NO_X Emissions (tons/yr)	PM_{10} Emissions (tons/yr)	SO_2 Emissions (tons/yr)
Dryer #1 (east)	5.03	15.09	0.0
Dryer #2 (west)			

1.3.3 PLYWOOD PRESSES (PV-1, PV-2, PV-3)

There are three steam heated presses which exhaust directly to the atmosphere. The #1 North Press was installed in 1983. The maximum hourly production rate is 20,000 ft^2/hr on a 3/8” basis.

The #2 Middle Press was installed before 1978. The maximum hourly production rate was 16,250 ft^2/hr - 3/8” basis. This press was modified in 2002 by adding six platens for a total of 30. This change increased the capacity from 16,250 to 20,000 ft^2/hr on a 3/8” basis.

The #3 South Press was installed before 1978. The maximum hourly production rate is 16,250 ft^2/hr - 3/8” basis. This press was modified in 2015 by adding six platens for a total of 30. This change increased the capacity from 16,250 to 20,000 ft^2/hr on a 3/8” basis.

The 2017 total annual emissions from all three presses are presented in Table 1-5.

Table 1-5. 2017 Annual Emissions – Plywood Presses

Emission Unit	PM_{10} Emissions (tons/yr)
#1 North Press	2.29
#2 Middle Press	
#3 South Press	

1.4 FOUR FACTOR ANALYSIS METHODOLOGY

As discussed previously, the analysis requires the following steps to identify the technologically feasible control options for each emission unit applicable to the four factor analysis:

- The cost of compliance;
- Time necessary for compliance;
- Energy and non-air environmental impacts; and
- Remaining useful life of the source.

The following steps must be followed in conducting the analysis:

- Identify all available control technologies
- Eliminate technically infeasible options; and
- Rank the remaining options based on effectiveness.

1.4.1 FACTOR 1 – COST OF COMPLIANCE

The basis for comparison in the economic analysis of the control scenarios is the cost effectiveness; that is, the value obtained by dividing the total net annualized cost by the tons of pollutant removed per year for each control technology. Annualized costs include the annualized capital cost plus the financial requirements to operate the control system on an annual basis, including operating and maintenance labor, and such maintenance costs as replacement parts, overhead, raw materials, and utilities. Capital costs include both the direct cost of the control equipment and all necessary auxiliaries as well as both the direct and indirect costs to install the equipment. Direct installation costs include costs for foundations, erection, electrical, piping, insulation, painting, site preparation, and buildings. Indirect installation costs include costs for engineering and supervision, construction expenses, start-up costs, and contingencies.

For each technically feasible control option, this analysis will summarize potential emission reductions, estimated capital cost, estimated annual cost, and cost-effectiveness (dollars per ton of pollutant). Per EPA guidance, SLR followed the methods in EPA's Air Pollution Control Cost Manual for this analysis.

1.4.2 FACTOR 2 – TIME NECESSARY FOR COMPLIANCE

Factor 2 involves the evaluation of the amount of time needed for full implementation of the different control strategies. The time for compliance will need to be defined and should include the time needed to develop and implement the regulations, as well as the time needed to install the necessary control equipment. The time required to install a retrofit control device includes time for capital procurement, device design, fabrication, and installation. The Factor 2 analysis should also include the time required for staging the installation of multiple control devices at a given facility if applicable.

1.4.3 FACTOR 3 – ENERGY AND OTHER IMPACTS

Energy and environmental impacts include the following but are not limited to and/or need to be included in the analysis:

Energy Impacts
- Electricity requirement for control equipment and associated fans
- Water required
- Fuel required

Environmental Impacts
- Waste generated
- Wastewater generated
- Additional carbon dioxide (CO_2) produced
- Reduced acid deposition
- Reduced nitrogen deposition
- Impacts to Regional Haze

Non-air environmental impacts (positive or negative) can include changes in water usage and waste disposal of spent catalyst or reagents. EPA recommends that the costs associated with non-air impacts be included in the Cost of Compliance (Factor 1). Other effects, such as deposition or climate change due to greenhouse gases (GHGs) do not have to be considered.

For this analysis, SLR evaluated the direct energy consumption of the emission control device, solid waste generated, wastewater discharged, acid deposition, nitrogen deposition, any offsetting negative impacts on visibility from controls operation, and climate impacts (e.g., generation and mitigation of greenhouse gas emissions).

In general, the data needed to estimate these energy and other non-air pollution impacts were obtained from the cost studies which were evaluated under Factor 1. These analyses generally quantify electricity requirements, increased water requirements, increased fuel requirements, and other impacts as part of the analysis of annual operation and maintenance (O&M) costs.

Costs of disposal of solid waste or otherwise complying with regulations associated with waste streams were included under the cost estimates developed under Factor 1 and were evaluated as to whether they could be cost-prohibitive or otherwise negatively affect the facility.

1.4.4 FACTOR 4 – REMAINING EQUIPMENT LIFE

Factor 4 accounts for the impact of the remaining equipment life on the cost of control. Such an impact will occur when the remaining expected life of a specific emission source is less than the lifetime of the pollution control device that is being considered. An appropriate useful life is selected and used to calculate emission reductions, amortized costs, and cost per ton of pollutant.

2. EMISSIONS CONTROL TECHNOLOGY ASSESSMENT

The emission control technology feasibility assessments were performed for the applicable units and pollutants in Table 2-1. Technical feasibility is demonstrated based on physical, chemical, or engineering principles.

Table 2-1. Applicable Unit

Emission Units	Pollutant(s)
South Boiler	PM_{10}, NO_X
North Boiler	PM_{10}, NO_X
Veneer Dryers	PM_{10}, NO_X
Plywood Press	PM_{10}

As outlined in the New Source Review (NSR) Workshop Manual (Draft), control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions or (2) the technology could be applied to the source under review.

2.1 SOUTH BOILER – WOOD/BARK FIRED

The South Boiler is a wood-fired dutch oven boiler with a maximum rated steam capacity of 35,000 lb/hr which is equivalent to approximately 49 MMBtu/hr of heat input. Actual NO_X emissions total 37.59 tons per year. The boiler was manufactured and installed in 1944, making it challenging to modify due to both its age and the dated dutch oven design. The boiler is considered an industrial boiler with a maximum heat input rate of less than 100 MMBtu/hr. As part of this analysis, the retrofit control technologies were identified by researching the U.S. EPA Reasonably Available Control Technology/Best Available Control Technology/Lowest Achievable Emission Rate (RACT/BACT/LAER) Clearinghouse (RBLC) database, engineering and permitting experiences, and surveying available literature.

2.1.1 NO_X CONTROL TECHNOLOGIES

In an industrial boiler, emissions of NO_X are formed in three ways: thermal, fuel bound, and prompt. Thermal NO_X is created by high flame temperature in the presence of oxygen. Fuel bound NO_X is inherent in fuel. Prompt NO_X is formed when nitrogen molecules in the air react with fuel during combustion. NO_x emission control technologies identified which may be available for use on the boiler are shown in Table 2-2.

Table 2-2. NO_X Control Technologies – South Boiler

Control Technology	Control Efficiency (%)	Technically Feasible
Good Combustion Practices	Base Case	Base Case – Feasible
Over Fire Air (OFA)	30-50	Infeasible
Low NO_X Burner (LNB)	30-60	Infeasible

Control Technology	Control Efficiency (%)	Technically Feasible
Flue Gas Recirculation	40-80	Infeasible
Selective Non-catalytic Reduction	25-50	Infeasible
Selective Catalytic Reduction	70-90	Infeasible

A description and evaluation of each of these control technologies is found in the following sections.

2.1.1.1 Good Combustion Practices

Good combustion practices can lower the emission of NO_X by using operational and design elements that optimize the amount and distribution of excess air in the combustion zone. Good combustion practices can be implemented by operating the boiler according to the manufacturer's recommendation, periodic inspections and maintenance, and periodic tuning of boilers to maintain excess air at optimum levels. Good combustion practices are currently used for the boiler and are considered technically feasible for this analysis.

2.1.1.2 Overfire Air

An overfire air (OFA) system is a combustion staging process that diverts a portion of the combustion air away from the primary combustion zone and creates an oxygen depleted zone that reduces the formation of NO_X. OFA systems have demonstrated NO_X reduction efficiencies of approximately 30% to 50%. Although OFA is commonly applied to wood-fired utility boilers, this system is not applied to dutch oven industrial boilers. OFA is also not listed as a control device for NO_X emissions from wood-fired boilers in the RBLC database. OFA retrofit is not considered technically feasible to install on the South Boiler due to the limited space between the top row of the burners and the convective pass. Therefore, OFA is removed from further consideration for the purpose for this analysis.

2.1.1.3 Low NO_X Burners

Low NO_X burners (LNBs) are a pre-combustion control technology that reduces combustion temperature and thus reduces the formation of thermal NO_X. The technology requires careful control of the fuel-air mixture during combustion. LNBs have demonstrated NO_X reduction efficiencies of approximately 30% to 60%. In order to apply an LNB in a wood fired boiler the technology generally requires pulverized fuel. The South Boiler is a dutch oven boiler which uses solid wood fuel in the burner. The solid fuel and the high moisture content in fuel would not create an appropriate environment needed for the effective operation of the LNB.

LNBs are also not listed as a control device for NO_X emissions from wood-fired boilers in the RBLC database. Therefore, LNBs are not considered a technically feasible control option for NO_X emissions from the combustion of solid wood fuel on the South Boiler.

2.1.1.4 Flue Gas Recirculation

Flue gas recirculation (FGR) requires recirculating a portion of relatively cool exhaust gases back into the combustion zone in order to lower the flame temperature and reduce NO_X formation. FGR has demonstrated NO_X reduction efficiencies of approximately 45%.

FGR technology in the boiler will require installing additional ductwork, combustion air fans, and additional structures to recirculate the flue gases from the boiler exhaust stack back into the combustion zone. Due to the extensive structural changes and addition of new equipment, FGR is difficult to retrofit on the existing boiler. The boiler is over 70 years old and the extensive structural changes required to install FGR are not feasible. The boiler also has extremely limited space for any new installation. Therefore, FGR is not considered technically feasible for the boiler.

2.1.1.5 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) is a post-combustion NO_X control technology in which a reagent (typically ammonia or urea) is injected into the exhaust gases to react chemically with NO_X, forming nitrogen and water. The success of this process in reducing NO_X emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas at a zone in the exhaust stream at which the flue gas temperature is within a narrow range, typically from 1,700°F to 2,000°F. To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 seconds. The consequences of operating outside the optimum temperature range are severe. Outside the upper end of the temperature range, the reagent will be converted to NO_X. Below the lower end of the temperature range, the reagent will not react with the NO_X and discharge from the stack (ammonia slip). SNCR systems are capable of sustained NO_X removal efficiency in the range of approximately 25% to 50%.

The exhaust temperature from the South Boiler is approximately 370°F based on the recent source test performed in 2018. However, as mentioned above, SNCR usually operates at gas temperatures ranging from 1,700°F to 2,000°F. In addition, there are also site-specific limitations (space requirement, age of the boilers) of installing all the necessary equipment required for this control technology. Therefore, SNCR is considered technically infeasible for the south boiler.

2.1.1.6 Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a post-combustion technology that employs ammonia in the presence of a catalyst to convert NO_X to nitrogen and water. The function of the catalyst is to lower the activation energy of the NO_X decomposition reaction. Therefore, the chemical reduction reaction between ammonia and NO_X occurs at much lower temperatures than those required for SNCR systems. The necessary temperature range for the SCR system depends on the type of catalysts. Most SCR systems operate in the range of 550°F to 750°F. However, high-temperature catalysts can operate above 750°F. Typical catalysts include vanadium pentoxide, titanium dioxide, noble metals, and tungsten trioxide.

Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, de-activation due to aging, ammonia slip emissions, and the design of the ammonia injection system. When properly designed and operated, SCR systems can achieve NO_X removal efficiencies in the range of 70% to 90%.

The exhaust temperatures from the boiler is approximately 370°F which is below the operating range of 550°F to 750°F for SCR. Furthermore, the PM emissions from the south boiler would foul and poison the catalyst. The deactivation of the catalyst would eliminate the application for SCR to control NO_X emissions. Therefore, SCR is considered technically infeasible for the boiler.

2.1.2 PM_{10} CONTROL TECHNOLOGIES

Particulate matter (PM) emissions from wood-fired boiler consist of unburned carbon particles (soot), condensable vapors, and noncombustible materials (ash). PM_{10} emission control technologies identified which may be available for use on the boiler are shown in Table 2-3.

Table 2-3. PM_{10} Control Technologies – South Boiler

Control Technology	Control Efficiency (%)	Technically Feasible
Multiclone	Base Case	Base Case – Feasible
Venturi Scrubber	90%	Infeasible
Electrostatic Precipitator (ESP)	99%	Feasible
Fabric Filters (Baghouse)	99%	Infeasible

A description and evaluation of each of these control technologies is found in the following sections.

2.1.2.1 Multiclones

Multiclones are mechanical collectors which use centrifugal forces to separate particulate matter from an exhaust gas stream and recirculate back to the boiler. This technology works best when operating according to the maximum pressure drop identified in the design specification. The south boiler is already equipped with multiclones to control PM_{10} emissions.

2.1.2.2 Venturi Scrubber

A venturi scrubber removes PM from the gas stream by capturing the particles in liquid droplets and separating the droplets from the gas steam. The droplets act as conveyors of the particulate out of the gas stream.

A venturi scrubber consists of three sections: converging, throat, and diverging. The flue gas and the scrubbing liquid enter the converging and the throat sections, where the atomization of the scrubbing liquid takes place through the velocity of the flue gas. The atomized liquid provides an enormous number of tiny droplets for the dust particles to impact on. The gas liquid mixture decelerates in the diverging section and the liquid droplets incorporating the particulate matter are separated from the gas stream in a cyclonic separator with a mist eliminator. A venturi scrubber can be designed to achieve a PM removal efficiency of 90%.

Venturi Scrubbers are not listed as a control device for PM_{10} emissions from wood-fired boilers in the RBLC database. Therefore, a venturi scrubber is not considered technically feasible and is removed from further consideration for the purpose of this analysis.

2.1.2.3 Fabric Filters

Fabric filters, also referred to as baghouses, remove PM from a gas stream by passing the stream through porous fabrics. The efficiency of the fabric filter increases as the dust particles form a porous cake on the surface of the fabric. However, the dust particles need to be frequently removed from the fabric in order to maintain the optimum pressure drop across the system. Fabric filters can be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are the most common type of fabric filter.

According to U.S. EPA-CICA Fact Sheet, operating conditions are important determinants of the choice of fabric filter. Some fabrics (e.g., polyolefins, nylons, acrylics, polyesters) are useful only at relatively low temperatures of 200°F to 300°F. For high temperature flue gas streams, more thermally stable fabrics such as fiberglass, Teflon®, or Nomex® must be used. Temperatures in excess of 550°F require special refractory mineral or metallic fabrics, which can be expensive. Fabric filter systems can be designed to have a PM removal efficiency in excess of 99%.

A fabric filter has the potential to experience filter clogging (blinding) for boilers that combust high moisture content fuels. In addition, according to US EPA’s AP-42, Section 1.6, fabric filters also have the potential to catch and/or cause fire that arises “from the collection of combustible carbonaceous fly ash.” Therefore, due to the risk associated with this technology, the fabric filter is not considered technically feasible for the South Boiler. Please note that there are no entries found in the RBLC that show fabric filters for wood-fired industrial boilers less than 100 MMBtu/hr.

2.1.2.4 Electrostatic Precipitator

Electrostatic precipitators (ESPs) use electrical forces to remove particulates from a gas stream and move them onto collector plates. PM in the gas stream is given an electrical charge when it passes through a corona, a region with gaseous ion flow. Electrodes are maintained at high voltage and generate the electrical field that forces PM to the collector walls. After PM is collected, it is knocked off or “rapped” by various mechanical means to dislodge the particulate for collection in hoppers. ESPs can be designed for a wide range of gas temperatures, and can handle temperatures up to 1300°F. ESPs are also capable of operating under high pressure (to 1,030 kPa (150 psi)) or vacuum conditions.

ESPs can be designed to have a PM removal efficiency of approximately 99%. Although, there are site-specific limitations (space requirement, age of the boilers), an ESP is considered technically feasible for the purpose of this analysis.

2.2 NORTH BOILER

The North Boiler is also a wood-fired dutch oven boiler with a maximum rated steam capacity of 12,500 lb/hr which is equivalent to approximately 17 MMBtu/hr of heat input. The emissions control technologies reviewed for the South Boiler are also applicable to the North Boiler. However, the North Boiler is rarely operated and the permitted emissions are extremely low. Due to the low emissions from this boiler and the high cost of any feasible control options identified for the South Boiler, application of good combustion practices are the only technically feasible control option for the North Boiler.

Table 2-4. Control Technology – North Boiler

Control Technology	Control Efficiency (%)	Technically Feasible
Good Combustion Practices	Base Case	Base Case – Feasible

2.3 VENEER DRYERS

CFP operates two veneer dryers (Dryer 1 and Dryer 2) equipped with natural gas burners. Dryer 1 and Dryer 2 have a maximum throughput of 13,000 ft^2/hour and 9,000 ft^2/hour, respectively. PM_{10} emissions from veneer dryers are the result of fuel combustion and condensable PM associated with higher weight gaseous organic compounds. NO_X emissions are associated with the natural gas combustion. The emissions from the veneer dryers are currently minimized by implementing best management practices which include operating the dryers in accordance with manufacturers' recommendations.

2.3.1 PM_{10} CONTROL TECHNOLOGIES

Multiple cyclones, electrified filter beds, wet scrubbers, and wet ESPs can be used to control PM_{10} emissions from the dryers. However, these control technologies are not commonly used for veneer dryers. There is only one entry found in the RBLC database that lists multiclones as a control technology for PM emission from a veneer dryer. The veneer dryers each include a heating zone and a cooling zone and each zone is equipped with several exhaust stacks. Due to multiple stacks associated with the dryers, it would be difficult to install add-on controls, such as a multiclone to successfully control emissions of PM. Therefore, for the purpose of this analysis, multiclones are not considered technically feasible for the veneer dryers.

Table 2-5. PM_{10} Control Technologies – Veneer Dryers

Control Technology	Control Efficiency (%)	Technically Feasible
Best Management Practice	Base case	Base Case – Feasible
Multiclone	10-40	Infeasible

2.3.2 NO_X CONTROL TECHNOLOGIES

LNBs are the only control technology identified in the RBLC database for veneer dryers. As mentioned previously, LNBs have demonstrated NO_X reduction efficiencies of approximately 30% to 60%. For the purpose of this analysis, LNBs are considered a technically feasible control option for NO_X emissions from the natural gas burners associated with the veneer dryers.

Table 2-6. NO_X Control Technologies – Veneer Dryers

Control Technology	Control Efficiency (%)	Technically Feasible
Best Management Practice	Base case	Base Case – Feasible
LNB	30-60	Feasible

2.4 PLYWOOD PRESSES

CFP operates three steam heated presses each with a maximum production of 20,000 ft^2 per hour. PM_{10} emissions from these presses consist of very fine wood materials and condensable PM from organic compounds. As shown in Table 1-5 the total permitted PM_{10} emissions from the presses are only 2.5 tpy. Due to the extremely low emissions from these presses and the high cost of any add-on emission controls, additional PM_{10} controls would not be feasible. The emissions from the presses are currently minimized by implementing best management practices which include operating the presses in accordance with manufacturers’ recommendations.

Table 2-7. Control Technology – Plywood Presses

Control Technology	Control Efficiency (%)	Feasibility
Best Management Practice	Base Case	Base Case – Feasible

3. FOUR FACTOR ANALYSIS

This section addresses the following four factors for the technologically feasible control options identified in Section 2 as requested by Oregon DEQ.

- Cost of compliance
- Time necessary for compliance
- Energy and non-air environmental impacts
- Remaining useful life of the source

For these four factors, this analysis followed EPA guidance[1] as well as EPA's Air Pollution Cost Manual.

3.1 FACTOR 1 – COST OF COMPLIANCE

The cost of compliance analysis estimated the capital cost, annual cost, and cost-effectiveness of each control option identified as technically feasible according to the methods and recommendations in the U.S. EPA's Air Pollution Control Cost Manual. The capital cost includes the equipment cost and the installation costs (direct and indirect). The annual cost includes O&M costs. The cost-effectiveness (dollar per ton of pollutant removed) is calculated using the total net annualized costs of control, divided by the actual tons of pollutant removed per year, for each control technology. The 2017 actual emissions for each applicable emission unit are used as baseline emissions for this analysis. The capital recovery factor applied in this analysis is 0.0786, based on a 20-year equipment life and 4.75% interest rate as noted in Oregon DEQ's *Fact Sheet – Regional Haze: Four Factor Analysis (December 5, 2019)*. The costs are adjusted to 2020 dollar values due to inflation. The detailed cost calculations are provided in Attachment A.

3.1.1 ESP – SOUTH BOILER

The capital and O&M costs for an ESP are based on the average cost data provided in U.S. EPA's *Air Pollution Control Technology – Fact Sheet (EPA 452/F-03-024)* and the design flowrate of the clay handling system. According to U.S. EPA document (EPA/452/B-02-001), the useful life of an ESP varies between 4 to 30 years and the typical useful life is about 20 years. Therefore, a useful life of 20 years was used for this analysis. Table 3-1 summarizes the costs of an ESP for the South Boiler. The cost effectiveness value of approximately \$11,400 per ton of PM_{10} removed is clearly excessive and indicates that the installation of an ESP is not cost effective for the South Boiler.

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[1] *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019)*

Table 3-1. Cost Effectiveness – ESP for South Boiler

Parameter	Value
Design Flowrate (scfm)	9,762
Total Capital Cost Total O&M Cost Total Annualized Cost	\$395,058 \$385,794 \$416,826
Control Efficiency (%)	99
PM_{10} Emissions Reduction (tons/yr)	36.43
Cost Effectiveness (\$/ton PM_{10} removed)	**11,441**

3.1.2 LNB – VENEER DRYERS

The capital and O&M costs for the LNB are based on the average cost data provided in Table 14 of U.S. EPA's *Technical Bulletin – Nitrogen Oxides (NO_x), Why and How They Are Controlled (EPA 456/F-99-006R, November 1999)* and the maximum heat rates of the dryers. Table 3-2 summarizes the costs of LNBs for the dryers. The cost effectiveness value of approximately $70,000 per ton of NO_X removed is clearly excessive and indicates that the installation of LNBs is not cost effective for each dryer.

Table 3-2. Cost Effectiveness – LNB for Veneer Dryer

Parameter	Dryer 1	Dryer 2
Maximum Heat Rate (MMBtu/hr)	36	41
Total Capital Cost Total O&M Cost Total Annualized Cost	\$291,600 \$59,940 \$82,845	\$332,100 \$68,265 \$94,352
Control Efficiency (%)	45	45
NO_x Emissions Reduction (tons/yr)	1.13	1.13
Cost Effectiveness (\$/ton NO_X removed)	**73,201**	**83,368**

3.2 FACTOR 2 – TIME NECESSARY FOR COMPLIANCE

This factor addresses the estimated time needed for the design and installation of the technically feasible control options. Per U.S. EPA's Technical document[2], the installation of LNBs may require up to 8 months. Due to the site specific constraints and age of the applicable units, installation of LNBs will be complex and may require additional time than provided by U.S. EPA guidance. A similar timeline is proposed for an ESP. The projected time for compliance is provided in Table 3-3. Although these control options have are already been deemed as not cost effective, the following information is provided per U.S. EPA guidance.

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[2] *Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance (November 2015)*

Table 3-3. Time for Compliance

Control Options	Time Necessary for Compliance
LNB (for Veneer Dryer)	12 Months (approx.)
ESP (for South Boiler)	12 Months (approx.)

3.3 FACTOR 3 – ENERGY AND NON-AIR ENVIRONMENTAL IMPACTS

This subsection addresses the energy and non-air environmental impacts associated with the installation and operation of the technically feasible control options. These impacts are based on the information from standard resources (e.g., U.S. EPA Technical documents) and professional experience and judgement.

3.3.1 ESP – SOUTH BOILER

The installation of an ESP for the South Boiler would increase the annual electric consumption of the facility. Electricity is required for the operation of a fan, electric field generation, and cleaning. The power required for a fan is dependent on the pressure drop across the ESP, the flowrate, and the operating time. The annual electricity cost is included in the O&M costs of the cost analyses summarized in Table 3-1. The non-environmental impacts include landfilling of solid waste generated in the form of the collected dust from operation of the ESP.

3.3.2 LNB – VENEER DRYERS

The energy impacts from the application of LNBs are expected to be minimal. However, the lower flame temperature associated with an LNB will decrease the efficiency and the performance of the burners. Therefore, to maintain the same amount of heat required for the dryers, the burners will be required to burn more fuel.

LNBs are not expected to have any non-air environmental impacts.

3.4 FACTOR 4 – REMAINING USEFUL LIFE OF SOURCE

Per EPA guidance, the useful life of the control equipment will be less than the useful life of the facility itself. Although most of the applicable units are more than 50 years old, CFP has no plan of shutting down any of the equipment currently. Therefore, the remaining useful life of the sources is assumed to be 20 years, which is the typical useful life of the control equipment.

4. CONCLUSIONS

At the request of the Oregon DEQ, a four factor analysis was prepared for CFP. The analysis identified technically feasible control options for applicable emission units and evaluated the technology for the following four statutory factors:

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

Based on the above evaluation, SLR has determined that it is not technically feasible or cost effective to implement additional emission controls for the emission units at CFP.

5. REFERENCES

United States Environmental Protection Agency (USEPA). 2017. Office of Air Quality Planning and Standards Control Cost Manual. Office of Air Quality Planning and Standards, Economic Analysis Branch, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. November. (Chapter 2, updated November, 2017)

USEPA. Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019)

USEPA. Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance (November 2015)

USEPA. Technical Bulletin – Nitrogen Oxides (NOx), Why and How They Are Controlled (EPA 456/F-99-006R, November 1999)

Oregon Department of Environmental Quality (DEQ). Fact Sheet – Regional Haze: Four Factor Analysis (December 5, 2019)

ATTACHMENT A

COST ANALYSIS

Table 1. ESP Retrofit Cost Effectiveness - South Boiler
Columbia Forest Products
Klamath Falls, Oregon

Parameter	Value	Reference
Design Flowrate (scfm)	9,762	2018 Source Test Data (1)
Capital Cost ($/scfm) in 2002 dollars	21.5	EPA-452/F-03-028 (Fact Sheet) - Average of Range (2)
O&M Cost ($/scfm) in 2002 dollars	21	EPA-452/F-03-028 (Fact Sheet) - Average of Range (2)
Capital Cost ($/scfm) in 2020 dollars	31.13	Adjusted for Inflation - CPI Inflation Calculator (3)
O&M Cost ($/scfm) in 2020 dollars	30.4	Adjusted for Inflation - CPI Inflation Calculator (3)
Total Capital Cost ($)	395,058	Design Rate (scfm) x 2020 Capital Cost ($/scfm) x Retrofit Factor (1.3) (4)
Total O&M Cost ($)	385,794	Design Rate (scfm) x 2020 O&M Cost ($/scfm) x Retrofit Factor (1.3) (4)
i, Interest Rate (%)	4.75	DEQ's Regional Haze; Four Factor Analysis - Fact Sheet (12/5/2019)
n, Equipment Life	20	EPA Cost Control Manual (4)
Capital Recovery Factor (CRF) =	0.08	i (1+ i)n/(1+ i)n - 1
Total Capital Investment (TCI) =	31,032	Total Capital Cost ($) x CRF
Total Annualized Cost ($) =	416,826	Total O&M Cost ($) + TCI ($)
Baseline PM_{10} Emissions (tons/yr)	36.80	2017 Annual Emissions
Control Efficiency (%)	99	Assumed
PM_{10} Reduction (tons/yr)	36.43	Baseline emissions x Control Efficiency/100
Cost Effectiveness ($/ton)	**11,441**	**Total Annual Cost/PM_{10} Removed/year**

Notes:

scfm = standard cubic feet per minute (flow rate)

O&M = Operations and Maintenance

1) Source Test Report - 2018 Compliance Testing - Columbia Forest Products - South Boiler (EU BLR-S), Klamath Falls, Oregon - Prepared by Montrose Air Quality Services, LLC (October 23, 2018)
2) U.S. EPA, Air Pollution Control Technology Fact Sheet, Dry Electrostatic Precipitator (ESP) - Wire-Plate Type (EPA-452/F-03-028)
3) CPI Inflation Calculator - Bureau of Labor Statistics - https://data.bls.gov/cgi-bin/cpicalc.pl
4) U.S. EPA, Cost Control Manual, Section 6, Chapter 3 - EPA/452/B-02-001, 2002. https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf

Table 2. Low NO_X Burner (LNB) Retrofit Cost Effectiveness - Veneer Dryers

Columbia Forest Products
Klamath Falls, Oregon

Parameter	Dryer 1	Dryer 2	Reference
Maximum Heat Input Rate (MMBtu/hr)	36	41	Design Specifications
Capital Cost ($/MMBtu) in 1993 dollars	4475	4475	Table 14. EPA-456/F-99-00R (November 1999) - Average of Range (1)
O&M Cost ($/MMbtu) in 1993 dollars	920	920	Table 14. EPA-456/F-99-00R (November 1999) - Average of Range (1)
Capital Cost ($/MMBtu) in 2020 dollars	8100	8100	Adjusted for Inflation - CPI Inflation Calculator (2)
O&M Cost ($/MMBtu) in 2020 dollars	1665	1665	Adjusted for Inflation - CPI Inflation Calculator (2)
Total Capital Cost ($)	291,600	332,100	Design Rate (MMBtu/hr) x 2020 Capital Cost ($/MMBtu)
Total O&M Cost ($)	59,940	68,265	Design Rate (MMBtu/hr) x 2020 O&M Cost ($/MMBtu)
i, Interest Rate (%)	4.75	4.75	DEQ's Regional Haze; Four Factor Analysis - Fact Sheet (12/5/2019)
n, Equipment Life	20	20	EPA Cost Control Manual (3)
Capital Recovery Factor (CRF) =	0.08	0.08	i (1+ i)n/(1+ i)n - 1
Total Capital Investment (TCI) =	22,905	26,087	Total Capital Cost ($) x CRF
Total Annualized Cost ($) =	82,845	94,352	Total O&M Cost ($) + TCI ($)
Baseline NO_X Emissions (tons/yr)	2.52	2.52	2017 Annual Emissions
Control Efficiency (%)	45	45	Chemical Engineering Progress (CEP), Magazine, January 1994 (4)
NO_X Reduction (tons/yr)	1.13	1.13	Baseline emissions x Control Efficiency/100
Cost Effectiveness ($/ton)	**73,201**	**83,368**	**Total Annual Cost/NO_X Removed/year**

Notes:

O&M = Operations and Maintenance

1) U.S. EPA, Technical Bulletin on Nitrous Oxides (Nox), Why and How They are Controlled, EPA-465/F-99-00R, 1999
https://www3.epa.gov/ttncatc1/dir1/fnoxdoc.pdf

2) CPI Inflation Calculator - Bureau of Labor Statistics - https://data.bls.gov/cgi-bin/cpicalc.pl

3) U.S. EPA, Cost Control Manual, EPA/452/B-02-001, 2002. https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf

4) Chemical Engineering Progress (CEP) Magazine, January 1994; ClearSign Combustion Corporation, May 2013

ATTACHMENT B

SUPPORTING DOCUMENTS

Table 1. Emissions Details
Regional Haze Four Factor Analysis
Columbia Forest Products - Klamath Falls. Oregon

Emissions Source	2017 Throughput	Permitted Throughput	Throughput Unit	Pollutant(s)	Emission Factor	Emission Factor Unit	Reference	2017 Emissions (tons/yr)	Permitted Emissions (tons/yr)
South Boiler (BLR-S)	144,588,000	175,200,000	lbs steam/yr	PM_{10}	0.50	lb/1000 lb steam	94% of PM -1994 ST	36.18	43.84
				SO_2	0.01	lb/1000 lb steam	DEQ factor	1.01	1.23
				NO_X	0.52	lb/1000 lb steam	Avg. of all valid ST	37.59	45.55
Noth Boiler (BLR-N)	0	35,040,000	lbs steam/yr	PM_{10}	0.30	lb/1000 lb steam	86% of PM - 1994 ST	0.00	5.28
				SO_2	0.01	lb/1000 lb steam	DEQ factor	0.00	0.25
				NO_X	0.37	lb/1000 lb steam	Avg. of all valid ST	0.00	6.48
Veneer Dryers (V-N)	83,829	162,540	MSF/yr	PM_{10}	0.36	lb/MSF	Avg. of all valid ST	15.09	29.26
				NO_X	0.12	lb/MSF	DEQ factor	5.03	9.75
Plywood Press (PV)	114,402	162,790	MSF/yr	PM_{10}	0.04	lb/MSF	2000 ST	2.29	3.26
Storage Pile (SP)	114,402	162,790	MSF/yr	PM_{10}	0.03	lb/MSF	EPA Fire factor (emission factors based on plywood production)	1.72	2.44
Material handling (cyclones, target box, baghouses)	114,402	162,790	MSF/yr	PM10	0.033	lb/MSF	EPA Fire factor (emission factors based on plywood production)	1.92	2.73

Table 1. RBLC Search - Wood-Fired Industrial Boilers less than 100 MMBtu/hr - PM_{10}

Permit Date Between 01/01/2010 And 05/14/2020

RBLCID	Facility Name	Facility State	Permit Number	Permit Issuance Date	Process Name	Primary Fuel	Throughput	Throughput Unit	Control Method Description	Emission Limit	Emission Limit Unit	Case-by-Case Basis
*WI-0276	LOUISIANA-PACIFIC CORPORATION	WI	14-DCF-189	4/2/2015	B11 & B12 Boilers	Wood Waste	19.4	mmBTU/hr	Cyclone, Wet Electrostatic Precipitator, and Thermal Oxidizer in series	6.1	LB/HR	BACT-PSD
*WI-0276	LOUISIANA-PACIFIC CORPORATION	WI	14-DCF-189	4/2/2015	B21 & B22 Boilers	Wood Waste	23.8	mmBTU/hr	Cyclone, Wet Electrostatic Precipitator, and Thermal Oxidizer in series	6.1	LB/HR	BACT-PSD

Table 2. RBLC Search - Wood-Fired Industrial Boilers less than 100 MMBtu/hr - NO_X
Permit Date Between 01/01/2010 And 05/14/2020

RBLCID	Facility Name	Facility State	Permit Number	Permit Issuance Date	Process Name	Primary Fuel	Throughput	Throughput Unit	Control Method Description	Emission Limit	Emission Limit Unit	Case-by-Case Basis
*WI-0276	LOUISIANA-PACIFIC CORPORATION	WI	14-DCF-189	4/2/2015	B11 & B12 Boilers	Wood Waste	19.4	mmBTU/hr	Good Combustion Practices	8.9	LB/HR	BACT-PSD
*WI-0276	LOUISIANA-PACIFIC CORPORATION	WI	14-DCF-189	4/2/2015	B21 & B22 Boilers	Wood Waste	23.8	mmBTU/hr	Good Combustion Practices	16.2	LB/HR	BACT-PSD

Table 1. RBLC Search - Natural Gas-Fired Veneer Dryer - PM_{10}
Permit Date Between 1/1/2000 And 05/14/2020

RBLCID	Facility Name	Facility State	Permit Number	Permit Issuance Date	Process Name	Throughput	Throughput Unit	Control Method Description	Emission Limit	Emission Limit Unit	Case-by-Case Basis
MT-0021	PLUM CREEK MANFACTURING, EVERGREEN FACILITY	MT	2602-08	8/10/2002	PLYWOOD VENEER DRYERS				12.6	LB/H	BACT-PSD
TX-0292	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	TX	PSD-TX-924	8/6/2000	REJECT VENEER DRYER, EPN19A/B	25000	SQ FT/H	CYCLONE A & B	1.5	LB/H	Other Case-by-Case

Table 2. RBLC Search - Natural Gas-Fired Veneer Dryer - NO$_X$
Permit Date Between 1/1/2000 And 05/14/2020

RBLCID	Facility Name	Facility State	Permit Number	Permit Issuance Date	Process Name	Throughput	Throughput Unit	Control Method Description	Emission Limit	Emission Limit Unit	Case-by-Case Basis
LA-0259	FLORIEN PLYWOOD PLANT	LA	PSD-LA-755	1/31/2012	Veneer Dryer No. 1- 4 Heated Zones			Low NOx Burners	8.49	LB/H	BACT-PSD
LA-0125	WILLAMETTE INDUSTRIES, INC.	LA	PSD-LA-627 (M-1)	1/7/2002	VENNER DRYER NO.2 COOLING ZONE				0.88	LB/H	BACT-PSD
LA-0125	WILLAMETTE INDUSTRIES, INC.	LA	PSD-LA-627 (M-1)	1/7/2002	VENEER DRYERS, HOT ZONES			RTO/RCO	10.27	LB/H	BACT-PSD
LA-0125	WILLAMETTE INDUSTRIES, INC.	LA	PSD-LA-627 (M-1)	1/7/2002	VENNER DRYER NO.1 COOLING ZONE				0.37	LB/H	BACT-PSD

REGIONAL HAZE FOUR-FACTOR ANALYSIS

OCHOCO LUMBER COMPANY

Prepared for

OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY

OCHOCO LUMBER COMPANY
(DBA) MALHEUR LUMBER COMPANY
June 10, 2020
Project No. 1461.01.03

Prepared by
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MAUL
FOSTER
ALONGI

CONTENTS

LIMITATIONS

TABLES

ACRONYMS AND ABBREVIATIONS

$/ton	dollars per ton of pollutant controlled
Analysis	Regional Haze Four Factor Analysis
CAA	Clean Air Act
Control Cost Manual	USEPA Air Pollution Control Cost Manual
DEQ	Oregon Department of Environmental Quality
ESP	electrostatic precipitator
°F	degrees Fahrenheit
facility	lumber and wood pellet/wood brick manufacturing facility located at 60339 West Highway 26, John Day, Oregon
Federal Guidance Document	USEPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003
HAP	hazardous air pollutant
MACT	Maximum Achievable Control Technology
MMBtu/hr	Million British thermal units per hour
Malheur	Malheur Lumber Company
MFA	Maul Foster & Alongi, Inc.
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO	nitric oxide
NO_x	oxides of nitrogen
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns or less
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
USEPA	U.S. Environmental Protection Agency

1 INTRODUCTION

The Oregon Department of Environmental Quality (DEQ) is developing a State Implementation Plan (SIP) as part of the Regional Haze program in order to protect visibility in Class I areas. The SIP developed by the DEQ covers the second implementation period ending in 2028 and must be submitted to the U.S. Environmental Protection Agency (USEPA) for approval. The second implementation period focuses on making reasonable progress toward national visibility goals, and assesses progress made since the 2000 through 2004 baseline period.

In a letter dated December 23, 2019, the DEQ requested that 31 industrial facilities conduct a Regional Haze Four Factor Analysis (Analysis). The Analysis estimates the cost associated with reducing visibility-impairing pollutants, including particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), oxides of nitrogen (NO_X), and sulfur dioxide (SO_2). The four factors that must be considered when assessing the states' reasonable progress, which are codified in Section 169A(g)(1) of the Clean Air Act (CAA), are:

(1) The cost of control,

(2) The time required to achieve control,

(3) The energy and non-air-quality environmental impacts of control, and

(4) The remaining useful life of the existing source of emissions.

The DEQ has provided the following three guidance documents for facilities to reference when developing their Analysis:

1) USEPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003 (Federal Guidance Document).

2) USEPA Air Pollution Control Cost Manual, which is maintained online and includes separate chapters for different control devices as well as several electronic calculation spreadsheets that can be used to estimate the cost of control for several control devices (Control Cost Manual).

3) Modeling Guidance for Demonstrating Air Quality Goals for Ozone, [particulate matter with an aerodynamic diameter of 2.5 microns or less] $PM_{2.5}$, and Regional Haze (November 2018), EPA-454/R-18-009.

The development of this Analysis has relied on these guidance documents.

1.1 Facility Description

Ochoco Lumber Company owns and operates Malheur Lumber Company (Malheur), a lumber and wood pellet/wood brick manufacturing facility located at 60339 West Highway 26, John Day, Oregon (the facility). The nearest Class I area is the Strawberry Mountain Wilderness, approximately 8.5

kilometers southeast of the facility. The facility currently operates under Standard Air Contaminant Discharge Permit number 12-0032-ST-01 issued by the DEQ on June 25, 2019. The facility is a minor stationary source of criteria pollutants and hazardous air pollutants (HAPs).

1.2 Process Description

1.2.1 Lumber Manufacturing

Logs received by the Malheur facility are debarked and bucked (cut) to the appropriate length. The cut log segments (blocks) are sawn into various pieces of dimensional lumber based on the size and shape of the blocks. Generated sawdust will be transferred to a load-out bin for other use or sale. Wood scraps from the sawmill will be hogged and used as boiler feed.

After sawing, the dimensional lumber is still green (wet) so it is stacked for drying in one of the onsite kilns, which are steam-heated. Depending upon the moisture and species of wood, the green lumber is dried for 50 or more hours. When dried to the appropriate final moisture content, the lumber is planed to final dimensions. Planer shavings are bagged and sold for uses such as animal bedding. Wood species utilized by the facility include, but are not limited to, Ponderosa Pine, White Fir, Hemlock, Douglas Fir, and Larch.

1.2.2 Torrefied-Wood Production

Green log shavings and wood chips will be stored outside at the north end of the property. A loader will place these materials into a hopper to feed an indirectly heated belt dryer, which dries the material to approximately 10% moisture. The belt dryer will use heat from the torrefier, a high temperature rotary kiln, to generate a high volume of low temperature air which will be passed through the wood on the belt. The dried materials from the belt dryer will be screened, then conveyed to the torrefier. Torrefied material will be conveyed in an enclosed drag chain conveyor to the densification process, which will consist of pelleting and/or briquetting equipment. In the event that there is decreased demand for torrefied wood, the facility will have the ability to bypass the torrefier and use the dry material to manufacture wood pellets.

2 APPLICABLE EMISSION SOURCES

Malheur retained Maul Foster & Alongi, Inc. (MFA) to assist the facility with completing this Analysis. Emissions rates for each visibility-impairing pollutant (PM_{10}, NO_X, and SO_2) were tabulated. These emissions rates represent a reasonable projection of actual source operation in the year 2028. As stated in the Federal Guidance Document,[1] estimates of 2028 emission rates should be used for the Analysis. It is assumed that current potential to emit (Plant Site Emission Limit) emission rates at the facility represent the most reasonable estimate of actual emissions in 2028.

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[1] See Federal Guidance Document page 17, under the heading "Use of actual emissions versus allowable emissions."

After emission rates were tabulated for each emissions unit, estimated emission rates for each pollutant were sorted from the highest emission rate to the lowest. The emission units collectively contributing to 90 percent of the total facility emissions rate for a single pollutant were identified and selected for the Analysis.

This method of emission unit selection ensures that larger emission units are included in the Analysis. Larger emission units represent the likeliest potential for reduction in emissions that would contribute to a meaningful improvement in visibility at federal Class I areas. It would not be reasonable to assess many small emission units—neither on an individual basis (large reductions for a small source likely would not improve visibility and would not be cost effective), nor on a collective basis (the aggregate emission rate would be no greater than 10 percent of the overall facility emissions rate, and thus not as likely to improve visibility at federal Class I areas, based solely on the relatively small potential overall emission decreases from the facility).

The following sections present the source selection, associated emission rates that will be used in the Analysis, and pertinent source configuration and exhaust parameters.

2.1 Sources of PM_{10} Emissions

A summary of the selected emission units and associated PM_{10} emission rates included in the Analysis is presented in the attached Table 2-1 (attached). A detailed description of each emissions unit is presented below, with the permit emission unit ID shown in parentheses.

2.1.1 Torrefier (TORR)

The direct-fired rotary kiln torrefaction unit (torrefier) is equipped with a low NO_X burner. Wood dried in the belt dryer is conveyed to the torrefier, where hemicellulose in the wood fibers undergoes thermal decomposition, producing low-heat synthesis gas (syngas). The propane burner used to heat the torrefier has a maximum rated heat input capacity of 44.1 million British thermal units per hour (MMBtu/hr).

The torrefier system incorporates syngas recirculation and combustion staging with tangential gas entry. This minimizes the amount of supplemental propane gas needed to maintain the torrefaction reaction. Process exhaust from the torrefier is routed to a thermal oxidizer for control of volatile organic compounds and organic HAP emissions.

2.1.2 Boiler 3 (BLR3)

Boiler 3 is a Hurst wood-fired boiler equipped with a low NO_X burner. It has a maximum rated heat input capacity of 58 MMBtu/hr. Boiler 3 was installed in 2019 but will not be through shakedown until late June of 2020. Steam produced from Boiler 3 is used to indirectly-heat the dry kilns for lumber production and the belt dryer. Process exhaust exiting Boiler 3 is routed to a downstream dry electrostatic precipitator (ESP) for control of fine particulate matter emissions.

Boiler 3 is subject to the National Emission Standards for Hazardous Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers Area Sources (Boiler MACT), codified at Title 40 Code of Federal Regulations 63, Subpart JJJJJJ, effective September 14, 2016. Based on the Federal Guidance Document, the USEPA believes it is reasonable for states to exclude a source for further analysis if

> For the purpose of particulate matter [PM] control measures, a unit that is subject to and complying with any CAA section 112 National Emission Standard for Hazardous Air Pollutants (NESHAP) or CAA section 129 solid waste combustion rule, promulgated or reviewed since July 31, 2013, that uses total or filterable PM as a surrogate for metals or has specific emission limits for metals. The NESHAPs are reviewed every 8 years and their emission limits for PM and metals reflects at least the maximum achievable control technology for major sources and the generally available control technology for area sources. It is unlikely that an analysis of control measures for a source meeting one of these NESHAPs would conclude that even more stringent control of PM is necessary to make reasonable progress.

Based on the Federal Guidance Document, and that Boiler 3 is already equipped with best-in-class control for fine particulate emissions, Boiler 3 was excluded from further evaluation in the Analysis.

2.1.3 Boilers 1 and 2 (BLR1 and BLR2)

Two Erie City water tube stoker wood-fired boilers (Boiler 1 and 2) are typically operated in a standby state as backup to Boiler 3. Each boiler has a maximum rated heat input capacity of 22.4 MMBtu/hr. The boilers supply steam to heat the dry kilns and the belt dryer. Process exhaust from each boiler is routed to multiclones for control of particulate emissions.

Each boiler is assumed to operate one at a time on an annual basis, for up to six months, at 50 percent load. However, on occasions of extreme weather, either Boiler 1 or 2 may operate at full load for short periods in addition to Boiler 3. In addition, at times where Boiler 3 is down for maintenance or repairs, both Boiler 1 and 2 may operate at full load.

Similar to Boiler 3, Boilers 1 and 2 are subject to the National Emission Standards for Hazardous Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers Area Sources (Boiler MACT), codified at Title 40 Code of Federal Regulations 63, Subpart JJJJJJ, effective September 14, 2016.

Boilers 1 and 2 have potential annual PM_{10} emissions of only 2.94 tons/yr combined. The boilers are separate emission points and each would require separate controls. MFA is unaware of any additional particulate controls that could be cost effectively applied. Given that they are permitted for limited use and they are primarily used as back-up to Boiler 3, Boilers 1 and 2 were excluded from further evaluation in the Analysis.

2.1.4 Unpaved Roads

The unpaved roads emissions unit is representative of fugitive emissions generated by vehicle traffic on unpaved roads. The facility conducts periodic sweeping and watering to on-site roads as preventative dust-control measures. Further control of the unpaved roads emissions unit is considered to be technically infeasible since capture and collection of emissions cannot reasonably be achieved. Therefore, the unpaved roads emissions unit was excluded from further evaluation in the Analysis.

2.2 Sources of NO_X Emissions

A summary of the selected emission units and associated NO_X emission rates to be evaluated in the Analysis is presented in the attached Table 2-2 (attached). As shown in the table, only Boiler 3 and the torrefier are included as a source for further evaluation in the Analysis. See Sections 2.1.1 and 2.1.2 for descriptions of the torrefier and Boiler 3 emissions units and associated existing control devices.

2.3 Sources of SO_2 Emissions

A summary of the selected emission units and associated SO_2 emission rates to be evaluated in the Analysis is presented in the attached Table 2-3 (attached). As shown in the table, only Boiler 3 is included as a source for further evaluation in the Analysis. See Section 2.1.2 for a description of the Boiler 3 emissions unit and associated existing control device.

2.4 Emission Unit Exhaust Parameters

A summary of the emission unit exhaust parameters to be evaluated further in this Analysis is presented in the attached Table 2-4 (attached). Emission units identified in the preceding sections as infeasible for control or as otherwise exempt are not presented. These emissions units will not be evaluated further in this Analysis.

3 REGIONAL HAZE FOUR FACTOR ANALYSIS METHODOLOGY

This Analysis has been conducted consistent with the Federal Guidance Document, which outlines six steps to be taken when addressing the four statutorily required factors included in the Analysis. These steps are described in the following sections.

3.1 Step 1: Determine Emission Control Measures to Consider

Identification of technically feasible control measures for visibility-impairing pollutants is the first step in the Analysis. While there is no regulatory requirement to consider all technically feasible measures, or any specific controls, a reasonable set of measures must be selected. This can be accomplished by identifying a range of options, which could include add-on controls, work practices that lead to emissions reductions, operating restrictions, or upgrades to less efficient controls, to name a few.

3.2 Step 2: Selection of Emissions

Section 2 details the method for determining the emission units and emission rates to be used in the Analysis. Potential to emit emission rates were obtained from the existing permit review report. These emissions rates represent a reasonable projection of actual source operation in the year 2028.

3.3 Step 3: Characterizing Cost of Compliance (Statutory Factor 1)

Once the sources, emissions, and control methods have all been selected, the cost of compliance is estimated. The cost of compliance, expressed in units of dollars per ton of pollutant controlled ($/ton), describes the cost associated with the reduction of visibility-impairing pollutants. Specific costs associated with operation, maintenance, and utilities at the facility are presented in Table 3-1 (attached).

The Federal Guidance Document recommends that cost estimates follow the methods and recommendations in the Control Cost Manual. This includes the recently updated calculation spreadsheets that implement the revised chapters of the Control Cost Manual. The Federal Guidance Document recommends using the generic cost estimation algorithms detailed in the Control Cost Manual in cases where site-specific cost estimates are not available.

Additionally, the Federal Guidance Document recommends using the Control Cost Manual in order to effect an "apples-to-apples" comparison of costs across different sources and industries.

3.4 Step 4: Characterizing Time Necessary for Compliance (Statutory Factor 2)

Characterizing the time necessary for compliance requires an understanding of construction timelines, which include planning, construction, shake-down and, finally, operation. The time that is needed to complete these tasks must be reasonable, and does not have to be "as expeditiously as practicable…" as is required by the Best Available Retrofit Technology regulations.

3.5 Step 5: Characterizing Energy and Non-air Environmental Impacts (Statutory Factor 3)

Both the energy impacts and the non-air environmental impacts are estimated for the control measures that were costed in Step 3. These include estimating the energy required for a given control method, but do not include the indirect impacts of a particular control method, as stated in the Federal Guidance Document.

The non-air environmental impacts can include estimates of waste generated from a control measure and its disposal. For example, nearby water bodies could be impacted by the disposed-of waste, constituting a non-air environmental impact.

3.6 Step 6: Characterize the Remaining Useful Life of Source (Statutory Factor 4)

The Federal Guidance Document highlights several factors to consider when characterizing the remaining useful life of the source. The primary issue is that often the useful life of the control measure is shorter than the remaining useful life of the source. However, it is also possible that a source is slated to be shut down well before a control device would be cost effective.

4 PM_{10} ANALYSIS

The Analysis for PM_{10} emissions follows the six steps previously described in Section 3.

4.1 Step 1—Determine PM_{10} Control Measures for Consideration

4.1.1 Baghouses

Baghouses, or fabric filters, are common in the wood products industry. In a fabric filter, flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to collect on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are one of the most common forms of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. The accumulated particles are periodically removed from the filter surface by a variety of mechanisms and are collected in a hopper for final disposition.

Typical new equipment design efficiencies are between 99 and 99.9 percent. Several factors determine fabric filter collection efficiency. These include gas filtration velocity, particle characteristics, fabric characteristics, and the cleaning mechanism. In general, collection efficiency increases with decreasing filtration velocity and increasing particle size. Fabric filters are generally less expensive than ESPs, and they do not require complicated control systems. However, fabric filters are subject to plugging for certain exhaust streams and do require maintenance and inspection to ensure that plugging or holes in the fabric have not developed. Regular replacement of the filters is required, resulting in higher maintenance and operating costs.

Certain process limitations can affect the operation of baghouses in some applications. For example, exhaust streams with very high temperatures may require specially formulated filter materials and/or render baghouse control infeasible. Additional challenges include the particle characteristics, such as materials that are “sticky” and tend to impede the removal of material from the filter surface. Exhaust gases that exhibit corrosive characteristics may also impose limitations on the effectiveness of baghouses. In wood products applications it is expected that particle characteristics, specifically particle and exhaust moisture content, may limit the feasibility on implementation.

Biomass dust from the torrefaction process is highly flammable at low temperatures. The exhaust temperature for the torrefier system is estimated to be 435 °F to 450 °F, well above temperatures that would pose a risk of fire or explosion in a baghouse. Based on the high risk of fire and explosion hazards, baghouse control is considered to be technically infeasible for control of PM_{10} emissions from the torrefier.

4.1.2 Wet Venturi Scrubbers

Wet scrubbers remove particulate from gas streams primarily by inertial impaction of the particulate onto a water droplet. In a venturi scrubber, the gas is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity, causing the water to shear into fine droplets. Particles in the gas stream then impact the water droplets. The entrained water droplets are subsequently removed from the gas stream by a cyclonic separator. Venturi scrubber control efficiency increases with increasing pressure drops for a given particle size. Control efficiency increases with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Control efficiencies are typically around 90 percent for particles with a diameter of 2.5 microns or larger.

Although wet scrubbers mitigate air pollution concerns, they also generate a water pollution concern. The effluent wastewater and wet sludge stream created by wet scrubbers requires that the operating facility have a water treatment system and subsequent disposal system in place. These consequential systems increase the overall cost of wet scrubbers and cause important environmental impacts to consider.

4.1.3 Electrostatic Precipitator

ESPs are used extensively for control of PM emissions. An ESP is a particulate control device that uses electrical force to move particles entrained with a gas stream onto collection surfaces. An electrical charge is imparted on the entrained particles as they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the corona that charges the particles, thereby allowing for their collection on the oppositely-charged collector walls. In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. Instead of the collection hoppers used by dry ESPs, wet ESPs utilize a drainage system and water treatment of some sort. In dry ESPs, the collectors are knocked, or "rapped," by various mechanical means to dislodge the collected particles, which slide downward into a hopper for collection.

Typical control efficiencies for new installations are between 99 and 99.9 percent. Older existing equipment has a range of actual operating efficiencies of 90 to 99.9 percent. While several factors determine ESP control efficiency, ESP size is the most important because it determines exhaust residence time; the longer a particle spends in the ESP, the greater the chance of collecting it. Maximizing electric field strength will maximize ESP control efficiency. Control efficiency is also affected to some extent by particle resistivity, gas temperature, chemical composition (of the particle and gas), and particle size distribution.

Similar to wet scrubber control systems, wet ESPs also create a water pollution concern as they reduce air pollution. Use of wet ESPs generates a wastewater and wet sludge effluent that requires treatment and subsequent disposal, thereby increasing the overall costs.

Biomass dust from the torrefaction process is highly flammable at low temperatures. The exhaust temperature for the torrefier system is estimated to be 435 °F to 450 °F, well above temperatures that would pose a risk of fire or explosion in a dry ESP. Based on the high risk of fire and explosion hazards, dry ESP control is considered to be technically infeasible for control of PM_{10} emissions from the torrefier.

The cost analyses for dry ESP installations are used as a surrogate for wet ESP. Wet ESP installations are expected to be higher due to the additional costs for wastewater treatment and disposal.

4.2 Step 2—Selection of Emissions

See Section 2.1 for descriptions of the PM_{10} emission units and emission rates selected for the Analysis.

4.3 Step 3—Characterizing Cost of Compliance

Tables 4-2 and 4-3 (attached) present the detailed cost analyses of the technically feasible PM_{10} control technologies included in the Analysis. A summary of the cost of compliance, expressed in $/ton, is shown below:

Table 4-1
Cost of Compliance Summary for PM_{10}

Emissions Unit	Emissions Unit ID	Cost of Compliance ($/ton)	
		Venturi Scrubber	ESP
Torrefier	TORR	22,951	27,344

4.4 Step 4—Characterizing Time Necessary for Compliance

Several steps will be required before the control device is installed and fully operational. After selection of a control technology, all of the following will be required: permitting, equipment procurement, construction, startup and a reasonable shakedown period, and verification testing. It is anticipated that it will take up to 18 months to achieve compliance.

4.5 Step 5—Characterizing Energy and Non-air Environmental Impacts

4.5.1 Energy Impacts

Energy impacts can include electricity and/or supplemental fuel used by a control device. Electricity use can be substantial for large projects if the control device uses large fans, pumps, or motors. Baghouse control systems require significant electricity use to operate the powerful fans required to overcome the pressure drop across the filter bags. Dry ESPs are expected to require even more electricity than baghouses, since high-voltage electricity is required for particle collection and removal. Dry ESPs also require powerful fans to maintain exhaust flow through the system. Similarly, wet venturi scrubbers and wet ESPs will use significant amounts of electricity to power large pumps used to supply water for the control device and the subsequent treatment process.

4.5.2 Environmental Impacts

Expected environmental impacts for baghouses and dry ESPs include the management of materials collected by the control devices. For sources where this material is clean wood residuals, it may be possible to reuse the material in the production process. However, collected materials that are degraded or that contain potential contaminants would be considered waste materials requiring disposal at a landfill.

As mentioned above, wet venturi scrubbers generate liquid waste streams, creating a water pollution issue. The effluent of wastewater and wet sludge generated by both control technologies will require the facility to have in place an appropriately sized water treatment system and subsequent waste disposal system and/or procedure. These systems increase the overall cost of installation and cause important environmental impacts to consider.

While none of the control technologies evaluated in the PM_{10} Analysis would require the direct consumption of fossil fuels, another, less quantifiable, impact from energy use may result from producing the electricity (i.e., increased greenhouse gases and other pollutant emissions). In addition, where fossil fuels are used for electricity production, additional impacts are incurred from the mining and use of fossil fuels for combustion.

4.6 Step 6—Characterize the Remaining Useful Life

It is anticipated that the remaining life of the emissions units, as outlined in the Analysis, will be longer than the useful life of the technically feasible control systems. No emissions units are subject to an enforceable requirement to cease operation. Therefore, in accordance with the Federal Guidance Document, the presumption is that the control system would be replaced by a like system at the end of its useful life. Thus, annualized costs in the Analysis are based on the useful life of the control system rather than the useful life of the emissions units.

5 NO_X ANALYSIS

The Analysis for NO_X emissions follows the six steps previously described in Section 3.

5.1 Step 1—Determine NO_X Control Measures for Consideration

5.1.1 Selective Non-catalytic Reduction

Selective non-catalytic reduction (SNCR) systems have been widely employed for biomass combustion systems. SNCR is relatively simple because it utilizes the combustion chamber as the control device reactor, achieving control efficiencies of 25 to 70 percent. SNCR systems rely on the reaction of ammonia and nitric oxide (NO) at temperatures of 1,550 to 1,950°F to produce molecular nitrogen and water, common atmospheric constituents, in the following reaction:

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

In the SNCR process, the ammonia or urea is injected into the combustion chamber, where the combustion gas temperature is in the proper range for the reaction. Relative to catalytic control devices, SNCR is inexpensive and easy to install, particularly in new applications where the injection points can be placed for optimum mixing of ammonia and combustion gases. The reduction reaction between ammonia and NO is favored over other chemical reactions at the appropriate combustion temperatures and is, therefore, a selective reaction. One major advantage of SNCR is that it is effective in combustion gases with a high particulate loading. Biomass combustion devices can produce exhaust that has a very high particulate loading rate from ash carryover to the downstream particulate control device. With use of SNCR, the particulate loading is irrelevant to the gas-phase reaction of the ammonia and NO.

One disadvantage of SNCR, and any control systems that rely on the ammonia and NO reaction, is that excess ammonia (commonly referred to as "ammonia slip") must be injected to ensure the highest level of control. Higher excess ammonia generally results in a higher NO_X control efficiency. However, ammonia is also a contributor to atmospheric formation of particulate that can contribute to regional haze. Therefore, the need to reduce NO_X emissions must be balanced with the need to keep ammonia slip levels acceptable. Careful monitoring to ensure an appropriate level of ammonia slip, not too high or too low, is necessary.

Additionally, in applications where SNCR is retrofitted to an existing combustion chamber (i.e., an existing boiler), substantial care must be used when selecting injection locations. This is because proper mixing of the injected ammonia cannot always be achieved in a retrofit, possibly because of limited space inside the boiler itself. For this reason, in retrofit applications it is common to achieve control efficiencies toward the lower end (25 percent) of the SNCR control efficiency range previously mentioned.

5.1.2 Selective Catalytic Reduction and Hybrid Systems

Unlike SNCR, selective catalytic reduction (SCR) reduces NO_X emissions with ammonia in the presence of a catalyst. The major advantages of SCR technology are the higher control efficiency (70 to 90 percent) and the lower temperatures at which the reaction can take place (400°F to 800°F, depending on the catalyst selected). SCR is widely used for combustion processes, such as those using natural gas turbines, where the type of fuel produces a relatively clean combustion gas. In an

SNCR/SCR hybrid system, ammonia or urea is injected into the combustion chamber to provide the initial reaction with NO_X emissions, followed by a catalytic (SCR) section that further enhances the reduction of NO_X emissions. The primary reactions that take place in the presence of the catalyst are:

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

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

$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O$

SCR is not widely used with wood-fired combustion units because of the amount of particulate that is generated by the combustion of wood. If not removed completely, the particulate can cause plugging in the catalyst and can coat the catalyst, reducing the surface area for reaction. Another challenge with wood-fired combustion is the presence of alkali metals such as sodium and potassium, which are commonly found in wood but not in fossil fuels. Sodium and potassium will poison catalysts, and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorus and arsenic.

Because of the likelihood of catalyst deactivation through particulate plugging and catalyst poisoning, SCR and SNCR/SCR hybrid systems are considered to be technically infeasible for control of NO_X emissions from wood-fired combustion units.

5.2 Step 2—Selection of Emissions

See Section 2 for a description of the NO_X emissions used in the Analysis.

5.3 Step 3—Characterizing Cost of Compliance

Table 5-2 (attached) presents the detailed cost analyses of the technically feasible NO_X control technologies included in the Analysis. A summary of the cost of compliance, expressed in $/ton, is shown below in Table 5-1.

Table 5-1
Cost of Compliance Summary for NO_X

Emissions Unit	Emissions Unit ID	Control Technology	Cost of Compliance ($/ton)
Boiler 3	BLR3	SNCR	10,140
Torrefier	TORR	SNCR	30,076

5.4 Step 4—Characterizing Time Necessary for Compliance

Several steps will be required before the control device is installed and fully operational. After selection of a control technology, all of the following will be required: permitting, equipment procurement, construction, startup and a reasonable shakedown period, and verification testing. It is anticipated that it will take up to 18 months to achieve compliance.

5.5 Step 5—Characterizing Energy and non-Air Environmental Impacts

5.5.1 Energy Impacts

Direct energy impacts will result from the use of SNCR control systems. Energy use (e.g. electricity use) is limited to the operation of pumps for urea injection into the SNCR and the heating of the urea storage tank. As a result, direct energy impacts are expected to be minimal. SNCR systems utilize urea or ammonia reagents, which result in the consumption of fossil fuels, primarily natural gas, during the production process. Additionally, combustion devices controlled by SNCR using urea require additional fuel consumption to offset the increased moisture loads caused by the urea injection in the flue gas.

5.5.2 Environmental Impacts

SNCR units require the use of urea (or aqueous ammonia) injection in the exhaust stream. Any unreacted excess ammonia in the exhaust stream (i.e., ammonia slip) will be released to the atmosphere. Ammonia slip to the atmosphere is a contributor to fine particle formation, which further exacerbates the regional haze issue; ammonia is also considered to be a toxic air contaminant with associated human health risks, and is regulated under the Cleaner Air Oregon Program. Therefore, there is a trade-off between maximizing NO_X emission reductions and minimizing the potential for ammonia slip. Additionally, increased fuel use by the combustion device or in the manufacture of reagents will lead to additional greenhouse gas contributions as well as other regulated pollutants.

5.6 Step 6—Characterize the Remaining Useful Life

It is anticipated that the remaining life of the emissions units, as outlined in the Analysis, will be longer than the useful life of the technically feasible control systems. No emissions units are subject to an enforceable requirement to cease operation. Therefore, in accordance with the Federal Guidance Document, the presumption is that the control system will be replaced by a like system at the end of its useful life. Thus, annualized costs in the Analysis are based on the useful life of the control system rather than the useful life of the emissions units.

6 SO_2 ANALYSIS

The Analysis for SO_2 emissions follows the six steps previously described in Section 3.

6.1 Step 1—Determine SO_2 Control Measures for Consideration

6.1.1 Dry Sorbent Injection

SO_2 scrubbers use a reagent to absorb, neutralize, and/or oxidize the SO_2 in the exhaust gas, depending on the selected reagent. In dry sorbent injection systems, powdered sorbents are pneumatically injected into the exhaust gas to produce a dry solid waste. As a result, use of dry sorbent injection systems requires downstream particulate-control devices to remove the dry solid waste stream. This waste product, will require landfilling or other waste management. For sources with existing particulate-control devices, retrofitting dry sorbent injection onto existing systems will increase the volume of fly ash and solid waste generated by the existing system.

Overall performance depends on the sorbent selected for injection and the exhaust gas temperature at the injection location. These parameters are driven in large part by the specific combustion unit configuration and space limitations. Control efficiencies for dry sorbent injection systems, including retrofit applications, range between 50 percent and 80 percent for control of SO_2 emissions. While higher control efficiencies can be achieved with dry sorbent injection in new installations or with wet SO_2 scrubber systems, the ease of installation and the smaller space requirements make dry sorbent injection systems preferable for retrofitting.

Dry sorbent injection systems introduce PM emissions into the exhaust stream, as mentioned above. This will cause increases to the particulate inlet loading of downstream particulate-control devices. For retrofit applications, it is likely that modification of the downstream existing particulate-control device will be necessary in order to accommodate the increased particulate inlet loading. It is anticipated that this increased loading may not be accommodated solely through modifications to the existing control device. Additional particulate controls may be required, resulting in cost increases and further energy and environmental impacts.

In addition, dry sorbent injection systems are commonly applied to high-sulfur-content fuel combustion systems, such as coal-fired boilers, but not to wood-fired boilers. The sulfur content of wood is quite low when compared to coal. It is also not certain that the control efficiency range, stated above, would be achievable when implemented on the emission units included in this SO_2 Analysis because of the low concentration of sulfur in the exhaust streams.

Therefore, the installation of dry sorbent injection systems on the emission units included in this SO_2 Analysis is not considered a feasible control option. Moreover, the potential for higher particulate emissions, which contribute to visibility issues, suggests that dry sorbent injection should not be assessed in this Analysis.

6.2 Step 2—Selection of Emissions

See Section 2.3 for a description of the SO_2 emissions used in the Analysis.

6.3 Step 3—Characterizing the Cost of Compliance

No technically feasible control technologies were identified for potential control of SO_2 emissions. Therefore, the cost of compliance is not applicable to this Analysis.

6.4 Step 4—Characterizing Time Necessary for Compliance

No technically feasible control technologies were identified for potential control of SO_2 emissions. Therefore, the time necessary for compliance is not applicable to this Analysis.

6.5 Step 5—Characterizing Energy and Non-air Environmental Impacts

Since no technically feasible control technologies were identified for SO_2 emissions, there are no energy and non-air environmental impacts to characterize.

6.6 Step 6—Characterize the Remaining Useful Life

No technically feasible control technologies were identified for SO_2 emissions; therefore, no characterization of the remaining useful life is necessary for the Analysis.

7 CONCLUSION

This report presents cost estimates associated with installing control devices at the John Day facility in order to reduce visibility-impairing pollutants in Class I areas, and provides the four factor analysis conducted consistent with available DEQ and USEPA guidance documents. Malheur believes that the above information meets the state objectives and is satisfactory for the DEQ's continued development of the SIP as a part of the Regional Haze program.

LIMITATIONS

The services undertaken in completing this report were performed consistent with generally accepted professional consulting principles and practices. No other warranty, express or implied, is made. These services were performed consistent with our agreement with our client. This report is solely for the use and information of our client unless otherwise noted. Any reliance on this report by a third party is at such party's sole risk.

Opinions and recommendations contained in this report apply to conditions existing when services were performed and are intended only for the client, purposes, locations, time frames, and project parameters indicated. We are not responsible for the impacts of any changes in environmental standards, practices, or regulations subsequent to performance of services. We do not warrant the accuracy of information supplied by others, or the use of segregated portions of this report.

TABLES

Table 2-1
PM_{10} Evaluation for Regional Haze Four Factor Analysis
Malheur Lumber Company—John Day, Oregon

Emission Units (1)	Emission Unit ID(s)	Current PM_{10} Control Technology (1)	Pollution Control Device ID	Annual PM_{10} Emissions (2) (tons/yr)	Control Evaluation Included?	Rationale for Exclusion from Control Evaluation	Emission Controls to Be Evaluated
Torrefier	TORR	--	--	13.1	Yes	--	Baghouse, Venturi Scrubber, Electrostatic Precipitator
Boiler 3	BLR3	Dry ESP	ESP	9.98	No	Source is directly regulated for filterable PM as a surrogate for metals under Area Source Boiler MACT (40 CFR 63 Subpart JJJJJJ), which became effective September 14, 2016. Therefore, this source meets USEPA guidance for no further analysis.	--
Boilers 1 & 2	BLR1, BLR2	Multiclone	MC	2.94	Yes	Source is directly regulated for filterable PM as a surrogate for metals under Area Source Boiler MACT (40 CFR 63 Subpart JJJJJJ), which became effective September 14, 2016. Therefore, this source meets USEPA guidance for no further analysis.	--
Unpaved Roads	FUG	Road Watering/ Sweeping	--	2.55	No	Fugitive source. No further control is technically feasible.	--
All Other Emission Units	Varies	Varies per Emissions Unit	--	1.98 (3)	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

Color Key
MFA-specific ID.

NOTES:
CFR = Code of Federal Regulations.
ESP = electrostatic precipitator.
PM_{10} = particulate matter with an aerodynamic diameter of 10 microns or less.
MACT = maximum achievable control technology.

REFERENCES:
(1) Information taken from the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued June 25, 2019 by the Oregon DEQ.
(2) Information taken from the Review Report for the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued June 25, 2019 by the Oregon DEQ.
(3) Each emission unit in the lower 10th percentile of the total facility emissions rates has potential PM_{10} emissions of 1.08 tons per year or less.

Table 2-2
NO_X Evaluation for Regional Haze Four Factor Analysis
Malheur Lumber Company—John Day, Oregon

Emission Units (1)	Emission Unit ID(s)	Current NO_X Control Technology (1)	Annual NO_X Emissions (2) (tons/yr)	Control Evaluation Included?	Rationale for Exclusion from Control Evaluation	Emission Controls to Be Evaluated
Boiler 3	BLR3	Low-NO_x Burner	55.9	Yes	--	SCR, SNCR
Torrefier	TORR	Low-NO_x Burner	14.4	Yes	--	SCR, SNCR
Boiler 1 & 2	--	--	6.08	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

NOTES:

NO_x = oxides of nitrogen.

SNCR = selective catalytic reduction.

SNCR = selective non-catalytic reduction.

REFERENCES:

(1) Information taken from the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued June 25, 2019 by the Oregon DEQ.

(2) Information taken from the Review Report for the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued June 25, 2019 by the Oregon DEQ.

Table 2-3

SO_2 Evaluation for Regional Haze Four Factor Analysis

Malheur Lumber Company—John Day, Oregon

Emission Units (1)	Emission Unit ID(s)	Current SO_2 Control Technology (1)	Annual SO_2 Emissions (2) (tons/yr)	Control Evaluation Included?	Rationale for Exclusion from Control Evaluation	Emission Controls to be Evaluated
Boiler 3	BLR3	--	6.35	Yes	--	Dry Sorbent Injection
All Other Emission Units	Varies	--	0.34	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

NOTES:

SO_2 = sulfur dioxide.

REFERENCES:

(1) Information taken from the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued June 25, 2019 by the Oregon DEQ.

(2) Information taken from the Review Report for the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued June 25, 2019 by the Oregon DEQ.

Table 2-4
Emissions Unit Input Assumptions and Exhaust Parameters
Malheur Lumber Company—John Day, Oregon

Emissions Unit ID	Emissions Unit Description	Heat Input Capacity (1) (MMBtu/hr)	Exhaust Parameters		
			Exit Temperature (°F)	Exit Flowrate	
				(acfm) (1)	(scfm) (a)
BLR1	Line 1 Boiler	22.4	475 (1)	15,200	7,716
BLR2	Line 2 Boiler	22.4	475 (1)	15,200	7,716
BLR3	Boiler 3	58.0	400 (1)	30,000	16,556
TORR	Torrefier	44.1	435 (2)	19,480	10,331

NOTES:

°F = degree Fahrenheit.

acfm = actual cubic feet per minute.

ft/sec = feet per second.

MMBtu/hr = million British thermal units per hour.

NO_x = oxides of nitrogen.

PM_{10} = particulate matter with an aerodynamic diameter of 10 microns or less.

scfm = standard cubic feet per minute.

SO_2 = sulfur dioxide.

(a) Exit flowrate (scfm) = (exit flowrate [acfm]) x (1 - [6.73E-06] x [facility elevation above sea level {ft}])$^{5.258}$
x (530) / (460 + [exit temperature {°F}])

Facility elevation above sea level (ft) = 3,087 (3)

REFERENCES:

(1) Data provided by Malheur Lumber Company.

(2) Information taken from the Review Report for the Standard Air Contaminant Discharge Permit no. 12-0032-ST-01 issued by the Oregon DEQ on June 25, 2019.

(3) Elevation above sea level obtained from publicly available online references.

Table 3-1
Operating and Maintenance Rates
Malheur Lumber Company—John Day, Oregon

Parameter	Value (units)		
FACILITY OPERATIONS			
Annual Hours of Operation	8,760	(hrs/yr)	(1)
Annual Days of Operation	365	(day/yr)	(1)
Daily Hours of Operation	24.0	(hrs/day)	(1)
UTILITY COSTS			
Electricity Rate	0.061	($/kWh)	(2)
Natural Gas Rate	2.49	($/MMBtu)	(1)
Water Rate	14.5	($/Mgal)	(2)
Compressed Air Rate	0.003	($/Mscf)	(2)
Water Disposal Rate	24.0	($/Mgal)	(2)
Landfill Disposal Fee	44.9	($/ton)	(2)
LABOR COSTS			
Maintenance Labor Rate	27.00	($/hr)	(2)
Operating Labor Rate	22.00	($/hr)	(2)
Supervisory Labor Rate	30.00	($/hr)	(2)
Operating Labor Hours per Shift	2.00	(hrs/shift)	(3)
Maintenance Labor Hours per Shift	1.00	(hrs/shift)	(3)
Typical Shifts per Day	3.00	(shifts/day)	(2)

NOTES:
Mgal = thousand gallons.
kW-hr = kilowatt-hour.
scf = standard cubic feet.

REFERENCES:
(1) Assumes continuous annual operation.
(2) Data provided by Malheur Lumber Company.
(3) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See table 1.5.1.1 and 1.5.1.3. Conservatively assumes the minimum labor requirement of range presented.

Table 4-2
Cost Effectiveness Derivation for Wet Venturi Scrubber Installation
Malheur Lumber Company—John Day, Oregon

Emissions Unit ID	Emissions Unit Description	Input Parameters			Pollutant Removed by Control Device [a] (tons/yr)	Operating Parameter		
		Exhaust Flowrate [1]		PM_{10} Annual Emissions Estimate [2] (tons/yr)		Pump and Fan Power Requirement [b] (kW)	Inlet Grain Loading [c] (gr/ft^3)	Annual Water Demand [c] (gal/yr)
		(acfm)	(scfm)					
TORR	Torrefier	19,480	10,331	13.1	13.0	62	0.018	664,506

Emissions Unit ID	Emissions Unit Description	Direct Costs			Total Indirect Costs [h]	Total Capital Investment [i]	Capital Recovery Cost of Control Device [j]	Direct Annual Costs								Total Indirect Annual Costs [q]	Total Annual Cost [r]	Annual Cost Effectiveness [s]
		Purchased Equipment Cost		Total Direct Cost [g]				Operating Labor		Maintenance		Utilities			Total Direct Annual Costs [15]			
		Basic Equip./Services Cost [e]	Total [f]					Operator Cost [l]	Supervisor Cost [m]	Labor Cost [l]	Material Cost [15]	Electricity Cost [n]	Water Usage Cost [o]	Wastewater Treatment Cost [p]				
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC_D	--	--	--	--	--	--	--	DAC	IAC	TAC	($/ton)
TORR	Torrefier	$186,407	$219,960	$343,138	$76,986	**$420,124**	$39,795	$48,180	$7,227	$29,565	$29,565	$32,921	$9,635	$15,948	$173,041	$125,322	**$298,363**	**$22,951**

Table 4-2
Cost Effectiveness Derivation for Wet Venturi Scrubber Installation
Malheur Lumber Company—John Day, Oregon

NOTES:

(a) Pollutant removed by control device (tons/yr) = (PM_{10} annual emissions estimate [tons/yr]) x (control efficiency [%] / 100)

Control efficiency (%) = 99.0 (3)

(b) Pump and fan power requirement (kW) = (typical pump and fan power requirement [hp/1,000 cfm]) x (exhaust flowrate [acfm]) x (kW/1.341 hp)

Typical water usage rate (gpm/1,000 acfm) = 4.27 (4)

(c) Inlet grain loading (gr/ft^3) = (PM_{10} annual emissions estimate [tons/yr]) x (2,000 lb/ton) x (7,000 gr/lb) / (exhaust flowrate [acfm]) x (hr/60 min) / (annual hours of operation [hrs/yr])

Annual hours of operation (hrs/yr) = 8,760 (5)

(d) Water demand (gal/yr) = (control efficiency [%] / 100) x (inlet grain loading [gr/ft^3]) x (lb/7,000 gr) x (exhaust flowrate [scfm]) x (60 min/hr) x (annual hours of operation [hrs/yr]) / (mass fraction of solids in recirculation water) / (density of water [lb/gal]); see reference (6).

Control efficiency (%) = 99.0 (3)
Annual hours of operation (hrs/yr) = 8,760 (5)
Mass fraction of solids in recirculation water = 0.25 (5)
Density of water (lb/gal) = 8.3 (5)

(e) Basic equipment/services cost ($) = (capital cost [2002 $/scfm]) x (exhaust flowrate [scfm]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 2002)

Capital cost ($/scfm) = 11.75 (3)
Chemical engineering plant cost index for 2019 = 607.5 (7)
Chemical engineering plant cost index for 2002 = 395.6 (7)

(f) Total purchased equipment cost ($) = (1.18) x (basic equipment/services cost [$]); see reference (8).

(g) Total direct cost ($) = (1.56) x (total purchased equipment cost [$]) + (site preparation cost, SP [$]) + (building cost, Bldg. [$]); see reference (8).

Site preparation cost, SP ($) = 0 (9)
Building cost, Bldg. ($) = 0 (9)

(h) Total indirect cost ($) = (0.35) x (total purchased equipment cost [$]); see reference (8).

(i) Total capital investment ($) = (total direct cost [$]) + (total indirect cost [$]); see reference (10).

(j) Control device capital recovery cost ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (11).

Control device capital recovery factor = 0.0947 (k)

(k) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs}] - 1); see reference (12).

Interest rate (%) = 4.75 (13)
Wet scrubber economic life (yr) = 15 (14)

(l) Operator or maintenance labor cost ($) = (staff hours per shift [hrs/shift]) x (staff shifts per day [shifts/day]) x (annual days of operation [days/yr]) x (staff labor rate [$/hr])

Operator labor rate ($/hr) = 22.00 (5)
Operating labor hours per shift [hrs/shift) = 2.00 (5)
Maintenance labor rate ($/hr) = 27.00 (5)
Maintenance labor hours per shift [hrs/shift) = 1.00 (5)
Shifts per day (shifts/day) = 3.00 (5)
Annual days of operation (days/yr) = 365 (5)

(m) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (15).

(n) Annual electricity cost ($) = (electricity rate [$/kWh]) x (total power requirement [kWh]) x (annual hours of operation [hrs/yr])

Electricity rate ($/kWh) = 0.061 (5)

(o) Annual water usage cost ($) = (annual water demand [gal/yr]) x (Mgal/1,000 gal) x (water rate [$/Mgal])

Water rate ($/Mgal) = 14.5 (5)

(p) Annual wastewater cost ($) = (annual water demand [gal/day]) x (Mgal/1,000 gal) x (sewage treatment rate [$/Mgal])

Sewage treatment rate ($/Mgal) = 24.0 (5)

(q) Total indirect annual cost ($) = (0.60) x ([operator labor cost {$}] + [supervisor labor cost {$}] + [maintenance labor cost {$}] + [maintenance material cost {$}]) + (0.04) x (total capital investment [$]) + (capital recovery cost [$]); see reference (15).

(r) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(s) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

Table 4-2
Cost Effectiveness Derivation for Wet Venturi Scrubber Installation
Malheur Lumber Company—John Day, Oregon

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.
(3) USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-017) for venturi scrubber issued July 15, 2003. Assumes the maximum PM control efficiency and average capital cost.
(4) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See table 2.3.
(5) See Table 3-1, Operating and Maintenance Rates.
(6) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See section 2.5.5.1, and equations 2.36 and 2.37.
(7) See Chemical Engineering magazine, Chemical Engineering Plant Cost Index (CEPCI) for annual indices.
(8) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See table 2.8.
(9) Conservatively assumes no costs associated with site preparation or building requirements.
(10) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See equation 2.42.
(11) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(12) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(13) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.5% as a default.
(14) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See section 2.6.2.2.
(15) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See table 2.9.

Table 4-3
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Malheur Lumber Company—John Day, Oregon

Emissions Unit ID	Emissions Unit Description	Input Parameters			Pollutant Removed by Control Device [(a)] (tons/yr)	Operating Parameter		
		Exhaust Flowrate [(1)]		PM_{10} Annual Emissions Estimate [(2)] (tons/yr)		System Pressure Drop [(4)] (inch w.c.)	Total Collection Plate Area Estimate [(b)] (ft^2)	ESP Inlet Grain Loading [(c)] (gr/ft^3)
		(acfm)	(scfm)					
TORR	Torrefier	19,480	10,331	13.1	13.0	6.0	4,132	0.018

Emissions Unit ID	Emissions Unit Description	Direct Costs			Total Indirect Costs [(f)]	Total Capital Investment [(g)]	Capital Recovery Cost of Control Device [(h)]	Direct Annual Costs										Total Indirect Annual Costs [(s)]	Total Annual Cost [(t)]	Annual Cost Effectiveness [(u)]
		Purchased Equipment Cost		Total Direct Cost [(e)]				Operating Labor			Maintenance		Utilities				Total Direct Annual Costs [(13)]			
		Basic Equip./Services Cost [(5)]	Total [(d)]					Operator Cost [(j)]	Supervisor Cost [(k)]	Coordinator Cost [(l)]	Labor Cost [(m)]	Material Cost [(n)]	Fan Electricity Cost [(o)]	Oper. Electricity Cost [(p)]	Compressed Air Cost [(q)]	Landfill Cost [(r)]				
USEPA COST MANUAL VARIABLE		**A**	**B**	**DC**	**IC**	**TCI**	**CRC_D**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**--**	**DAC**	**IAC**	**TAC**	**($/ton)**
TORR	Torrefier	$604,474	$713,280	$1,191,177	$263,914	**$1,455,091**	$114,298	$48,180	$7,227	$16,060	$6,416	$7,133	$11,228	$4,255	$30,716	$749	$131,964	$223,511	**$355,474**	**$27,344**

Table 4-3
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Malheur Lumber Company—John Day, Oregon

NOTES:

(a) Pollutant removed by control device (tons/yr) = (PM$_{10}$ annual emissions estimate [tons/yr]) x (control efficiency [%] / 100)
Control efficiency (%) = 99.0 (3)

(b) Total collection plate area estimate (ft^2) = (average specific collection area [ft^2/1,000 scfm]) x (exhaust flowrate [scfm])
Average specific collection area (ft^2/1,000 scfm) = 400 (3)

(c) ESP inlet grain loading (gr/ft^3) = (PM$_{10}$ annual emissions estimate [tons/yr]) x (2,000 lb/ton) x (7,000 gr/lb) / (exhaust flowrate [acfm]) x (hr/60 min) / (annual hours of operation [hrs/yr])
Annual hours of operation (hrs/yr) = 8,760 (6)

(d) Total purchased equipment cost ($) = (1.18) x (basic equipment/services cost [$]); see reference (7).

(e) Total direct cost ($) = (1.67) x (total purchased equipment cost [$]) + (site preparation cost, SP [$]) + (building cost, Bldg. [$]); see reference (7).
Site preparation cost, SP ($) = 0 (8)
Building cost, Bldg. ($) = 0 (8)

(f) Total indirect cost ($) = (0.37) x (total purchased equipment cost [$]); see reference (8).

(g) Total capital investment ($) = (total direct cost [$]) + (total indirect cost [$]); see reference (7).

(h) Control device capital recovery cost ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (9).
Control device capital recovery factor = 0.0786 (i)

(i) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs}] - 1); see reference (10).
Interest rate (%) = 4.75 (11)
Dry ESP economic life (yr) = 20 (12)

(j) Operator labor cost ($) = (operator hours per shift [hrs/shift]) x (operating shifts per day [shifts/day]) x (annual days of operation [days/yr]) x (operator labor rate [$/hr])
Operator labor rate ($/hr) = 22.00 (6)
Operating labor hours per shift [hrs/shift) = 2.00 (6)
Shifts per day (shifts/day) = 3 (6)
Annual days of operation (days/yr) = 365 (6)

(k) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (13).

(l) Coordinator labor cost ($) = (1/3) x (operator labor cost [$]); see reference (13).

(m) Maintenance labor cost ($-1999) = (maintenance labor cost [$-1999]) / (1999 annual chemical engineering plant cost index) x (2019 annual chemical engineering plant cost index)
Maintenance labor cost ($-1999) 4,125 (14)
1999 annual chemical engineering plant cost index = 390.6 (14)
2019 annual chemical engineering plant cost index = 607.5 (14)

(n) Maintenance material cost ($) = (0.01) x (total purchased equipment cost [$]); see reference .

(o) Annual fan electricity cost ($) = (0.000181) x (exhaust flowrate [acfm]) x (system pressure drop [inch w.c.]) x (annual hours of operation [hrs/yr]) x (electricity rate [$/kWh])
Annual hours of operation (hrs/yr) = 8,760 (6)
Electricity rate ($/kWh) = 0.061 (6)

(p) Annual operating power electricity cost ($) = (1.94E-03) x (total collection plate area estimate [ft^2]) x (annual hours of operation [hrs/yr]) x (electricity rate [$/kWh])
Annual hours of operation (hrs/yr) = 8,760 (6)
Electricity rate ($/kWh) = 0.061 (6)

(q) Annual compressed air cost ($) = (compressed air cost [$/Mscf]) x (Mscf/1,000 scf) x (exhaust flowrate [acfm]) x (60 min/hr) x (annual hours of operation [hrs/yr])
Compressed air cost ($/Mscf) = 0.003 (6)
Annual hours of operation (hrs/yr) = 8,760 (6)

(r) Annual landfill cost ($) = (4.29E-06) x (ESP inlet grain loading [gr/ft^3]) x (annual hours of operation [hrs/yr]) x (exhaust flowrate [acfm]) x (landfilling cost [$/ton]); see reference (13).
Annual hours of operation (hrs/yr) = 8,760 (6)
Landfilling cost ($/ton) = 57.00 (6)

(s) Total indirect annual cost ($) = (0.60) x ([operator labor cost {$}] + [supervisor labor cost {$}] + [maintenance labor cost {$}] + [maintenance material cost {$}]) + (0.04) x (total capital investment [$]) + (capital recovery cost [$]); see reference (13).

(t) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(u) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

Table 4-3
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Malheur Lumber Company—John Day, Oregon

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.

(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.

(3) USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-028) for dry electrostatic precipitator, wire-plate type issued July 15, 2003. Assumes the typical collection area and minimum new equipment design control efficiency.

(4) PPC Industries Quotation no. 18048/18049 (Revision 0) dated September 12 and 13, 2018. MFA obtained two separate costs and equipment requirements for dry ESPs sized at 21,000 acfm and 51,000 acfm. For the smallest exhaust flowrate above (MC4), the quoted data was scaled using a ratio. All other costs/data were scaled and obtained using tread line formulas. It is important to note that the quoted costs do not include the costs associated with taxes, freight, mechanical construction, electrical work, excavation, building/foundation upgrades, and permitting or licensing.

(5) excavation, building/foundation upgrades, and permitting or licensing.

(6) See Table 3-1, Operating and Maintenance Rates.

(7) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.16 "Capital Cost Factors for ESPs."

(8) Conservatively assumes no costs associated with site preparation or building requirements.

(9) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.

(10) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.

(11) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.

(12) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See section 3.4.2.

(13) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.21.

(14) See Chemical Engineering magazine, chemical engineering plant cost index section for annual indices.

Table 5-2
Cost Effectiveness Derivation for SNCR Installation
Malheur Lumber Company—John Day, Oregon

Emissions Unit ID	Emissions Unit Description	Input Parameters				Pollutant Removed by Control Device		Normalized Stoichiometric Ratio [(e)]	Operating Parameters				
		Heat Input Capacity [(1)] (MMBtu/hr)	Uncontrolled NO_X Emissions Estimate		Uncontrolled NO_X Emissions in Flue Gas [(b)] (lb/MMBtu)				Reagent Mass Consumption [(f)] (lb/hr)	Reagent Solution Flowrate [(g)] (gal/hr)	Power Demand [(h)] (kW)	Water Demand [(i)] (gal/hr)	Additional Fuel Usage [(j)] (MMBtu/hr)
			Hourly [(a)] (lb/hr)	Annual [(3)] (tons/yr)		Hourly [(c)] (lb/hr)	Annual [(d)] (tons/yr)						
		Q_B	--	--	NO_{Xin}	--	--	NSR	$m_{reagent}$	q_{sol}	P	q_{water}	ΔFuel
BLR3	Boiler 3	58.0	12.8	55.9	0.22	3.19	14.0	1.30	10.8	2.27	35.8	10.3	0.087
TORR	Torrefier	44.1	3.29	14.4	0.075	0.82	3.60	2.85	6.11	1.29	35.4	5.86	0.049

Emissions Unit ID	Emissions Unit Description	Direct Cost	Indirect Cost	Total Capital Investment [(m)]	Capital Recovery Cost of Control Device [(n)]	Direct Annual Costs							Total Indirect Annual Costs [(w)]	Total Annual Cost [(x)]	Annual Cost Effectiveness [(y)]
						Maintenance Labor and Material Cost [(p)]	Reagent Usage [(q)]	Utilities				Total Direct Annual Costs [(27)]			
		Capital Cost [(k)]	Balance of Plant Cost [(l)]					Electricity Cost [(s)]	Water Usage Cost [(t)]	Fuel Additive Cost [(u)]	Ash Disposal Cost [(v)]				
USEPA COST MANUAL VARIABLE		$SNCR_{COST}$	BOP_{COST}	TCI	CR	--	--	--	--	--	--	DAC	IDAC	TAC	($/ton)
BLR3	Boiler 3	$153,247	$437,150	**$892,391**	$70,098	$13,386	$37,049	$18,988	$1,313	$312	$34	$71,082	$70,499	**$141,582**	**$10,140**
TORR	Torrefier	$116,601	$339,465	**$717,761**	$56,380	$10,766	$20,994	$18,809	$744	$177	$19	$51,510	$56,703	**$108,214**	**$30,076**

Table 5-2
Cost Effectiveness Derivation for SNCR Installation
Malheur Lumber Company—John Day, Oregon

NOTES:

(a) Uncontrolled hourly NO_X emissions estimate (lb/hr) = (uncontrolled annual NO_X emissions estimate [tons/yr]) x (2,000 lb/ton) / (annual hours of operation [hrs/yr])

Annual hours of operation (hrs/yr) = 8,760 (2)

(b) Uncontrolled NO_X emissions in flue gas (lb/MMBtu) = (uncontrolled hourly NO_X emissions estimate [lb/hr]) / (heat input capacity [MMBtu/hr])

(c) Hourly pollutant removed by control device (lb/hr) = (uncontrolled hourly NO_X emissions estimate [lb/hr]) x (control efficiency [%] / 100)

Control efficiency (%) = 25.0 (4)

(d) Annual pollutant removed by control device (tons/yr) = (uncontrolled annual NO_X emissions estimate [tons/yr]) x (control efficiency [%] / 100)

Control efficiency (%) = 25.0 (4)

(e) Normalized stoichiometric ratio = ([2] x [uncontrolled NOX emissions in flue gas {lb/MMBtu}] + [0.7]) x (control efficiency [%] / 100) / (uncontrolled NOX emissions in flue gas [lb/MMBtu]); see reference (5).

Control efficiency (%) = 25.0 (4)

(f) Reagent mass consumption (lb/hr) = (uncontrolled NOX emissions in flue gas [lb/MMBtu]) x (heat input capacity [MMBtu/hr]) x (normalized stoichiometric ratio) x (60.06 lb-urea/lb-mole) / (46.01 lb-NO_2/lb-mole) / [theoretical stoichiometric ratio]); see reference (6).

Theoretical stoichiometric ratio = 2 (7)

(g) Reagent solution flowrate (gal/hr) = (reagent mass consumption [lb/hr]) / (aqueous reagent solution concentration [%] / 100) / (aqueous reagent solution density [lb/ft^3]) x (7.4805 gal/ft^3); see reference (8).

Aqueous reagent solution concentration (%) = 50.0 (8)

Aqueous reagent solution density (lb/ft^3) = 71.0 (8)

(h) Power demand (kW) = (0.47) x (uncontrolled NOX emissions in flue gas [lb/MMBtu]) x (normalized stoichiometric ratio) x (heat input capacity [MMBtu/hr]) / (net plant heat rate [MMBtu/MWh]); see reference (9). + (power required to heat tank [kW]); see reference (11).

Net plant heat rate (MMBtu/MWh) = 10.0 (10)

Power required to heat tank (kW) = 35.0 (11)

(i) Water demand (gal/hr) = (4) x (reagent mass consumption [lb/hr]) / (aqueous reagent solution concentration [%] / 100) / (density of water [lb/gal]); see reference (12).

Aqueous reagent solution concentration (%) = 50.0 (8)

Density of water (lb/gal) = 8.345

(j) Additional fuel usage (MMBtu/hr) = (9) x (heat of vaporization of water [Btu/lb]) x (reagent mass consumption [lb/hr]) x (MMBtu/1,000,000 Btu); see reference (22).

Heat of vaporization of water (Btu/lb) = 900 (13)

(k) Capital cost ($) = (capital cost [1999 $/MMBtu/hr]) x (heat input capacity [MMBtu/hr]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 1999)

Capital cost ($/MMBtu/hr) = 1,700 (4)

Chemical engineering plant cost index for 2019 = 607.5 (14)

Chemical engineering plant cost index for 1999 = 390.6 (14)

(l) Balance of plant costs ($) = (213,000) x ([heat input capacity {MMBtu/hr}] / [net plant heat rate {MMBtu/MWh}])^(0.33) x (hourly pollutant removed by control device [lb/hr])^(0.12) x (retrofit factor); see reference (13).

Net plant heat rate (MMBtu/MWh) = 10.0 (10)

Retrofit factor = 1.00 (15)

(m) Total capital investment ($) = (1.3) x ([capital cost {$}] + [balance of plant cost {$}]) + (reagent storage tank cost [$]) + (reagent storage tank construction [$]); see reference (24).

Reagent storage tank ($) = 74,875 (17)

Reagent storage area construction ($) = 50,000 (18)

(n) Control device capital recovery cost ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (25).

Control device capital recovery factor = 0.0786 (o)

(o) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs}] - 1); see reference (17).

Interest rate (%) = 4.75 (21)

SNCR economic life (yr) = 20 (22)

(p) Annual maintenance cost ($) = (0.015) x (total capital investment [$]); see reference (23).

(q) Annual reagent usage cost ($) = (reagent solution flowrate [gal/hr]) x (reagent cost [$/50% urea solution]) x (annual hours of operation [hrs/yr])

Table 5-2
Cost Effectiveness Derivation for SNCR Installation
Malheur Lumber Company—John Day, Oregon

Reagent rate ($/50% urea solution) = 1.86 (r)
Annual hours of operation (hrs/yr) = 8,760 (2)

(r) Reagent rate ($/50% urea solution) = (reagent cost [2016 $/50% urea solution]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 2016)

Reagent rate (2016 $/50% urea solution) = 1.66 (4)
Chemical engineering plant cost index for 2019 = 607.5 (14)
Chemical engineering plant cost index for 2016 = 541.7 (14)

(s) Annual electricity cost ($) = (power demand [kWh]) x (electricity rate [$/kWh]) x (annual hours of operation [hrs/yr])

Electricity rate ($/kWh) = 0.061 (2)
Annual hours of operation (hrs/yr) = 8,760 (2)

(t) Annual water usage cost ($) = (water demand [gal/hr]) x (Mgal/1,000 gal) x (water rate [$/Mgal]) x (annual hours of operation [hrs/yr])

Water rate ($/Mgal) = 14.5 (2)
Annual hours of operation (hrs/yr) = 8,760 (2)

(u) Annual fuel additive cost ($) = (high heating value estimate [Btu/lb) x (reagent mass consumption [lb/hr]) x (9) x (MMBtu/1,000,000 Btu) x (fuel rate [$/MMBtu]) x (annual hours of operation [hrs/yr]); see reference (23).

High heat value of wood (MMBtu/BDT) = 17.48 (25)
Wood fuel rate ($/BDT) = 21.00 (2)
Annual hours of operation (hrs/yr) = 8,760 (2)

(v) Ash disposal ($) = (additional fuel usage [MMBtu/hr]) x (ash production [wt%])/100 x (annual hours of operation [hrs/yr]) / (high heat value of wood [MMBtu/BDT]) x (landfill disposal rate [$/ton]); see reference (25).

Ash production (wt%) = 1.75 (27)
Annual hours of operation (hrs/yr) = 8,760 (2)
High heat value of wood (MMBtu/BDT) = 17.48 (25)
Landfill disposal rate ($/ton) = 44.90 (2)

(w) Total indirect annual cost ($) = (0.03) x (annual maintenance cost [$]) + (capital recovery cost [$]); see reference (29).

(x) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(y) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 3-1, Operating and Maintenance Rates.
(3) See Table 2-2, NO_X Evaluation for Regional Haze Four Factor Analysis.
(4) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-031) for selective non-catalytic reduction (SNCR) issued July 15, 2003. Assumes the average PM control efficiency and average capital cost.
(5) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.17.
(6) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.18.
(7) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. Assumes theoretical stoichiometric ratio for urea.
(8) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equations 1.19 and 1.20.
(9) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.42.
(10) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.3.1.
(11) Information provided by Chromalox vendor. Assumes heating of urea is required to a minimum of 95°F.
(12) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.45.
(13) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.48.
(14) See Chemical Engineering magazine, Chemical Engineering Plant Cost Index (CEPCI) for annual indices.
(15) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.37. Assumes retrofit factor.
(16) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.35.

Table 5-2
Cost Effectiveness Derivation for SNCR Installation
Malheur Lumber Company—John Day, Oregon

(17) Cost for storage tank and heating unit. Includes shipping and installation costs.

(18) Cost for construction of covered tank storage area and secondary containment.

(19) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.

(20) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.

(21) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.

(22) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.4.2.

(23) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.39.

(24) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.49.

(25) 40 CFR, Subchapter C, Part 98, Subpart C. See Table C-1 "Default CO2 Emission Factors and High Heat Values of Various Types of Fuel". Factor for wood and wood residuals.

(26) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equations 1.50 and 1.51.

(27) Average wood ash production from burning of hogged fuel.

(28) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.38.

(29) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.52 and 1.53.

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June 9, 2020

Ali Mirzakhalili, Air Quality Division Administrator
Oregon Department of Environmental Quality
700 NE Multnomah Street, Suite 600
Portland, OR 97232
Ph: (503) 229 - 5696

Re: Regional Haze Four Factor Analysis; Pacific Wood Laminates, Inc.

Dear Mr. Mirzakhalili:

Pacific Wood Laminates, Inc. (PWL) is submitting the enclosed Regional Haze Four-Factor Analysis report as required by the Oregon Department of Environmental Quality (ODEQ) letter dated December 23, 2019. PWL was identified by ODEQ as a significant source of regional haze precursor emissions to the Kalmiopsis Wilderness in Oregon, thus requiring a four-factor analysis under the Regional Haze Program. Representatives of PWL participated in the informational webinar on the Regional Haze Program hosted by ODEQ on January 9, 2020. PWL is confident that the enclosed report meets the requirements of the four-factor analysis.

Please call (541) 254-1447 with any questions regarding this evaluation and report.

Certification

Based upon information and belief formed after a reasonable inquiry, I, as a responsible official of the above-mentioned facility, certify the information contained in this report is accurate and true to the best of my knowledge.

Sincerely,

Nolan Roy

Nolan Roy
Plywood and Veneer Operations Manager
Pacific Wood Laminates, Inc.

CC D Pei Wu, Oregon DEQ, via email at wu.d@deq.state.or.us

Enclosure

REGIONAL HAZE FOUR-FACTOR ANALYSIS

Pacific
Wood Laminates,
Inc.

Prepared on behalf of:
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Prepared by:

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June 11, 2020

EXECUTIVE SUMMARY

Bison Engineering, Inc. (Bison) was retained by Pacific Wood Laminates, Inc. (PWL) to prepare a four-factor analysis on potential regional haze precursor emission controls at their wood products facility in Brookings, 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 relates to “Round 2” 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 potential emission control options at PWL that, if implemented, could be used to attain “reasonable progress” toward visibility goals in Oregon Class I areas.

The four-factor analysis was conducted to assess the control of emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_x) and particulate matter less than ten micrometers (PM_{10}). The analysis calculates a cost effectiveness for adding equipment to control NO_x and PM_{10} emissions from the biomass-fired boiler and evaluates visibility impact from additional sources at PWL. The analysis ultimately showed that the cost effectiveness for additional emission controls is not considered economically feasible.

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ACRONYMS

BACT	Best Available Control Technology
BAER	Burned Area Emergency Response
BART	Best Available Retrofit Technology
BDT	Bone Dry Ton
BLM	Bureau of Land Management
BOP	Balance of Plant Cost
Btu	British Thermal Unit
CAA	Clean Air Act
CEMs	Continuous Emissions Monitor System
CEPCI	Chemical Engineering Plant Cost Index
CFR	Code of Federal Regulations
Control Cost Manual	EPA Air Pollution Control Cost Manual
dV	Deciview
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
F	Degrees Fahrenheit
HAP	Hazardous Air Pollutant
HHV	Higher Heating Value
IMPROVE	Interagency Monitoring of Protected Visual Environments
Klb or Mlb	Thousand pounds
km	Kilometer
lb	Pound
lb/MMBtu	Pounds per million British thermal units
lb/hr	Pounds per hour
LP	Louisiana-Pacific
m	Meter
MACT	Maximum Achievable Control Technology
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
NCASI	National Council for Air and Stream Improvement
NEI	National Emissions Inventory
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
O&M	Operations and Maintenance Cost
ODEQ	Oregon Department of Environmental Quality
PCWP	Plywood and Composite Wood Products
PH1	Brookings Plywood Dutch-Oven Boiler 1 (Decommissioned)
PH2	Riley Hogged-Fuel Boiler (Operating)
PM	Particulate matter
PM_{10}	Particulate matter less than ten micrometers
PSEL	Plant Site Emission Limit
PWL	Pacific Wood Laminates
RBLC	RACT/BACT/LAER Clearinghouse
RCO	Regenerative Catalytic Oxidizer
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 Goal
RSCR	Regenerative Selective Catalytic Reduction
RTO	Regenerative Thermal Oxidizer
SCA	Specific Collection Area
SCL	South Coast Lumber
SCR	Selective catalytic reduction
SIP	State Implementation Plan
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
TAP	Toxic Air Pollutant
TBACT	Best Available Control Technology for Toxics
TPY	Tons per year
TSD	2008 Electric Generating Unit NO_x Mitigation Strategies Proposed Rule Technical Support Document
USFS	United States Forest Service
USGS	United States Geographical Survey
UTM	Universal Transverse Mercator
Wellons	Vendor Providing Control Equipment Quotes
WRAP	Western Regional Air Partnership

1.0 INTRODUCTION

1.1 Basis of the Four-Factor Analysis

The Federal Clean Air Act was amended in 1977 (42 USC 7401 *et. seq.*) to include a declaration by Congress claiming a national goal to be "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)). Plans and requirements were then codified in the Code of Federal Regulations (CFR), primarily within 40 CFR 51.308, to address that goal. The entire visibility program is now found in 40 CFR 51.300 – 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)).

The federal visibility rules were revised in 1999 to specifically address regional haze. Since then, ODEQ has submitted several revisions of their SIP to the Environmental Protection Agency (EPA) for review and approval addressing visibility. During the first planning period of the Regional Haze Program (Round 1), ODEQ focused on NO_x, SO_2, and organic carbon emissions as the key pollutants contributing to regional haze and visibility impairment (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. ODEQ did not specifically review the PWL Brookings 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 the second "planning period", requires an additional step toward reasonable progress in meeting the national goal of attaining natural visibility conditions in mandatory Class I areas by 2064. ODEQ chose facility-level emissions of NO_x, SO_2, and PM_{10} to be considered for potential reduction as part of the Round 2 reasonable progress analysis. These pollutants were selected based on monitoring data from the Interagency Monitoring of Protected Visual Environments (IMPROVE) program [1] and is consistent with other Western Regional Air Partnership (WRAP)[1] states. ODEQ found that these three pollutants contribute to visibility impairments 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 reasonable progress toward the visibility goal. These four factors are collectively known as the four-factor analysis and are as follows:

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[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/

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 PWL 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 emission sources at the facility (Appendix A).

1.2 PWL Qualification

PWL was selected for the four-factor analysis based on a “Q/d” analysis. The “Q/d” analysis was referenced by ODEQ in the December 2019 Round 2 letter and is also 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 detailed in Table 1-1. If the Q/d evaluation exceeds 5 then the facility is required to perform a four-factor analysis. ODEQ evaluated Q/d qualification based on actual emissions and permit-based plant site emission limits (PSELs) where “Q” accounts for combined emissions of PM_{10}, SO_2 and NOx and “d” is the distance to the nearest mandatory Class I area. Both evaluations are included in the following table.[2]

Table 1-1: PWL Q/d Evaluation

Basis	Distance (km)	Emissions (tpy)				Q/d
	"d"	NOx	PM10	SO2	"Q"	
Actual Emissions (2017 NEI)	23.5	52.5	139.12	3.27	195	8.3
PSELs (Regional Haze Call-In)	23.5	76	189	29	294	12.5
PSELs (New Title V)	23.5	102	132	39	273	11.6

The Kalmiopsis Wilderness Area is approximately 23.5 kilometers (km) to the east and northeast of PWL and is the Class I area evaluated in the four-factor analysis. Actual emissions are based on the 2017 National Emissions Inventory (NEI) while the PSELs are based on the facility Title-V permit 08-0003-TV-01. The “Regional Haze Call-In” PSEL emissions listed in Table 1-1 were applicable at the time of the Q/d evaluation by ODEQ. PWL was issued a renewed Title V permit on December 30, 2019 with a combined PSEL

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[2] Q/d analysis provided by ODEQ at https://www.oregon.gov/deq/FilterDocs/haze-QDFacilitiesList.pdf

for PM_{10}, SO_2 and NO_x of 273 tons. This is also included in the table. The PWL facility exceeds the Q/d requirement based on either actual or potential emissions.

The initial Q/d analysis used to prompt 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 is the Riley hogged-fuel boiler (Hogged-fuel boiler or PH2). The Q/d for the PH2 alone, using the new permit PSEL values, would also exceed the Round 2 threshold. The veneer dryers and plywood presses combined have about the same PM_{10} emissions as PH2, but they have only trace NOx or SO_2 emissions. A complete analysis of emission sources at the PWL facility is included in Section 4.4. This includes the criteria and selection of sources evaluated in the 4-factor analysis.

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 by 2064.[3] The RHR itself was promulgated 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 the best available retrofit technology (BART) analysis and the four-factor analysis. This evaluated potential contributions toward Reasonable Progress Goals (RPGs) of the program. 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. PWL 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. The timeframe for Round 1 has since expired and the RHR now requires the implementation of Round 2. The second planning period is meant to show an incremental progress toward the national goal for the 10-year period of 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 in the Kalmiopsis Wilderness is the representative dataset for this analysis of PWL’s impact on visibility.

Figure 2-1 shows a summary of the IMPROVE monitoring data at the Kalmiopsis station for the years 2000 through 2018. Visibility degradation caused by anthropogenic (human-based) sources is defined as “impairment”. Whereas visibility-reducing “haze” is caused by natural and anthropogenic sources.[4] The results of the IMPROVE monitor indicate that the primary pollutants accounting for the most impairment is ammonium sulfate [2]. Industrial SO_2 emissions are indicative of precursor ammonium sulfate impacts in the context of the Regional Haze program. The primary pollutant that accounts for most haze is organic carbon matter. Wildfire smoke is the major source of organic carbon matter in the air and is the largest contributor to light extinction at nearly all sites on the worst days. The Chetco Bar fire and other regional fires in Southern Oregon contributed heavily and exponentially to the wildfire smoke in 2017 and 2018 timeframe. During this time, PWL

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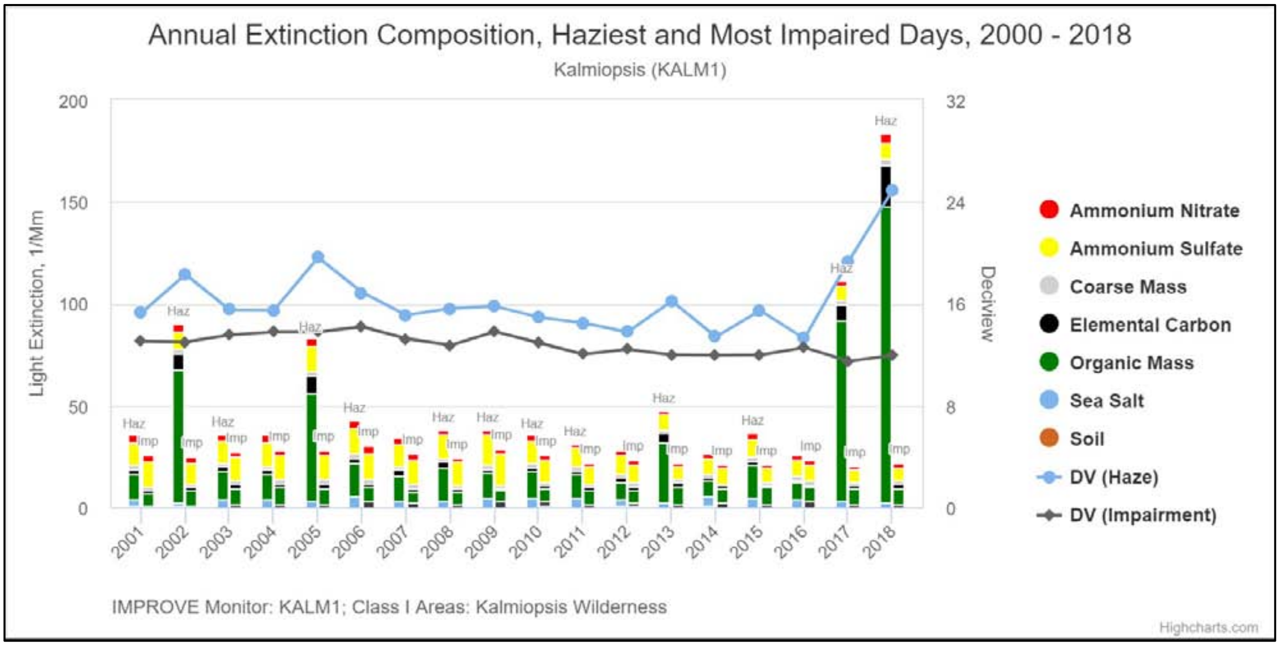
[3] A mandatory Class I area is usually a national park or wilderness area above a certain threshold size (4,000 or 5,000 acres) and in existence on or before August 7, 1977.

[4] Haze and impairment definitions are detailed for the IMPROVE monitoring network at http://vista.cira.colostate.edu/Improve/impairment/

and affiliated ownership experienced a complete loss of 14,000 acres of company fee timberlands that were managed in a sustained yield fashion. Additional wildfire losses include an estimated 200,000 acres of U.S. Forest Service (USFS), Bureau of Land Management (BLM), and other smaller private fee timberlands. Limited treatments were proposed by the USFS Burned Area Emergency Response (BAER) effort which included road and trail treatments, protection and safety treatments, and land treatments for cultural site protection and noxious and invasive plants.[5] The USFS's intent is do very little additional treatment (no active replanting -reforestation) to the USFS and BLM lands. The USFS states that "regeneration is expected to be slow in areas far from seed sources"[6] therefore it is likely that the burned area will be prone to naturally occurring wind erosion and large fugitive PM/PM_{10} emissions from the Chetco wind effect until regeneration has occurred. Once more, the large contribution of organic carbon is likely due to summer wildfire activity. Figure 4-3 (later in the report) provides the impact area of the Chetco Bar Fire in relation to PWL and the Kalmiopsis Wilderness.

Figure 2-1: IMPROVE Visibility Data for Kalmiopsis Wilderness Area



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.

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[5] Chetco Bar Fire BAER Request: https://www.fs.usda.gov/Internet/FSE_DOCUMENTS/fseprd563154.pdf

[6] USFS Talking Points – Chetco Bar Fire Recovery Efforts: https://www.fs.usda.gov/Internet/FSE_DOCUMENTS/fseprd585134.pdf

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 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 regarding new source review permitting and the other addressing "regional haze." Regional haze may be further broken down into the BART program and the reasonable progress program. The underlying reason for this review of the Brookings 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 Pacific Wood Laminates

Oregon is tasked with establishing a plan for "*reasonable progress*" in carrying out the incremental improvement to visibility. ODEQ notified PWL 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[7] in a Class I area).

To that end, PWL has elected to not only analyze various control "options" utilizing four factors but has also included a qualitative analysis of impacts the Brookings facility may have on the closest Class I Area, the Kalmiopsis Wilderness Area. 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].

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[7] 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.

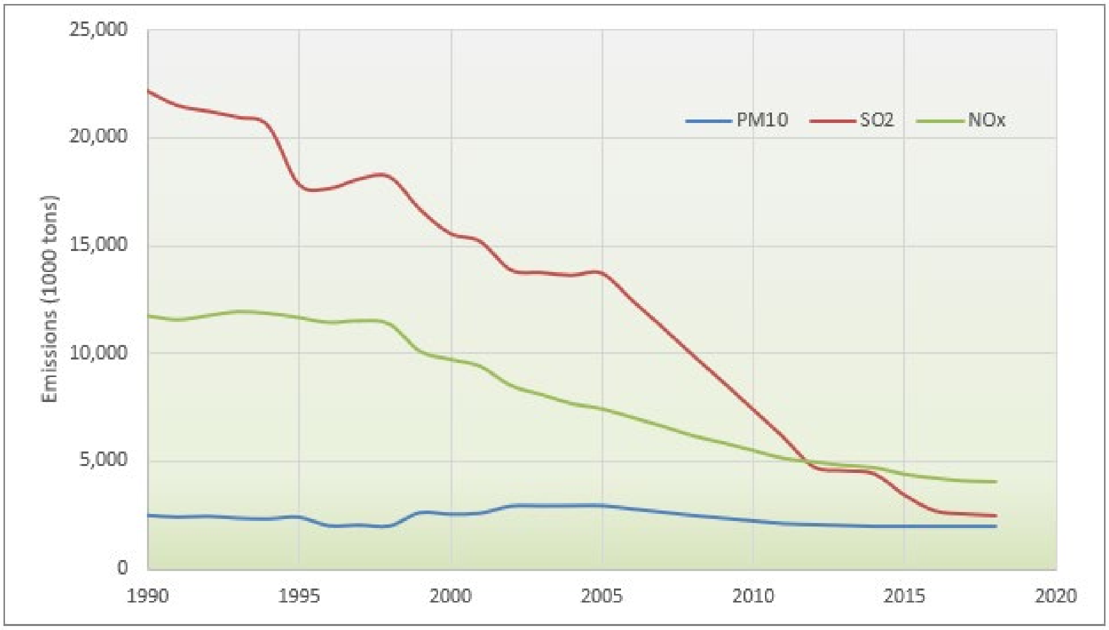
3.0 REASONABLE PROGRESS PERSPECTIVE

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 nationwide and statewide.

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.[8]

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



Substantial reductions in industrial SO_2 and NOx emissions 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

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[8] 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

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 discussed below, emissions reductions in the state of Oregon are also on target to meet the goal.

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, Industrial, & 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[9]	Agriculture and Forestry Other Combustion (*excluding forest fires*) Catastrophic/Accidental Releases Repair Shops Health Services Cooling Towers Fugitive Dust

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

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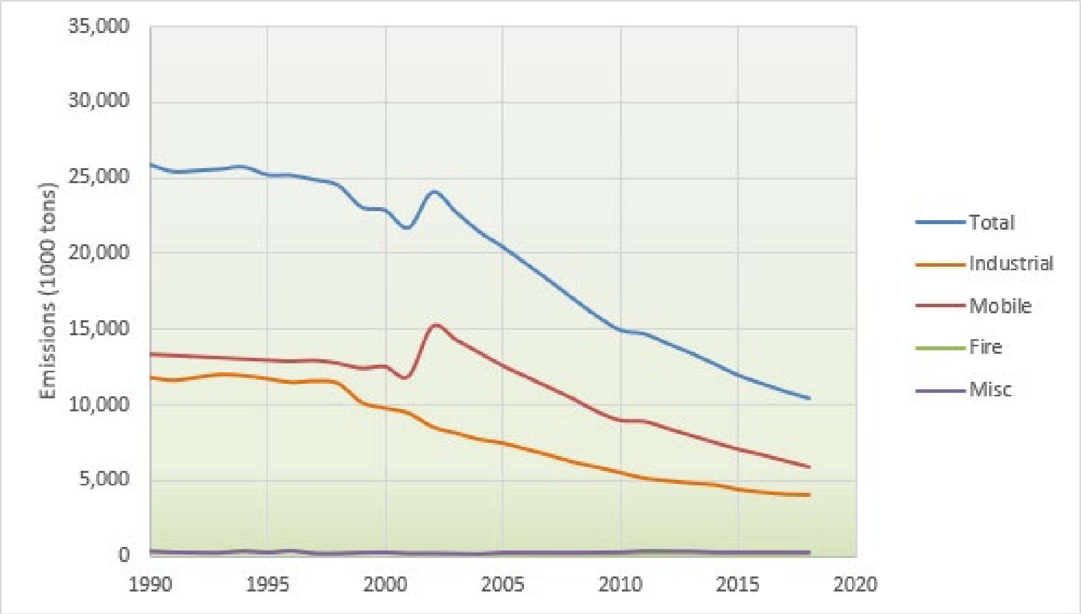
[9] Miscellaneous source categories are listed in Table 4.1-2 of the Procedures Document for National Emission Inventory Criteria Air Pollutants, 1985-1999.
https://www.epa.gov/sites/production/files/2015-07/documents/aerr_final_rule.pdf

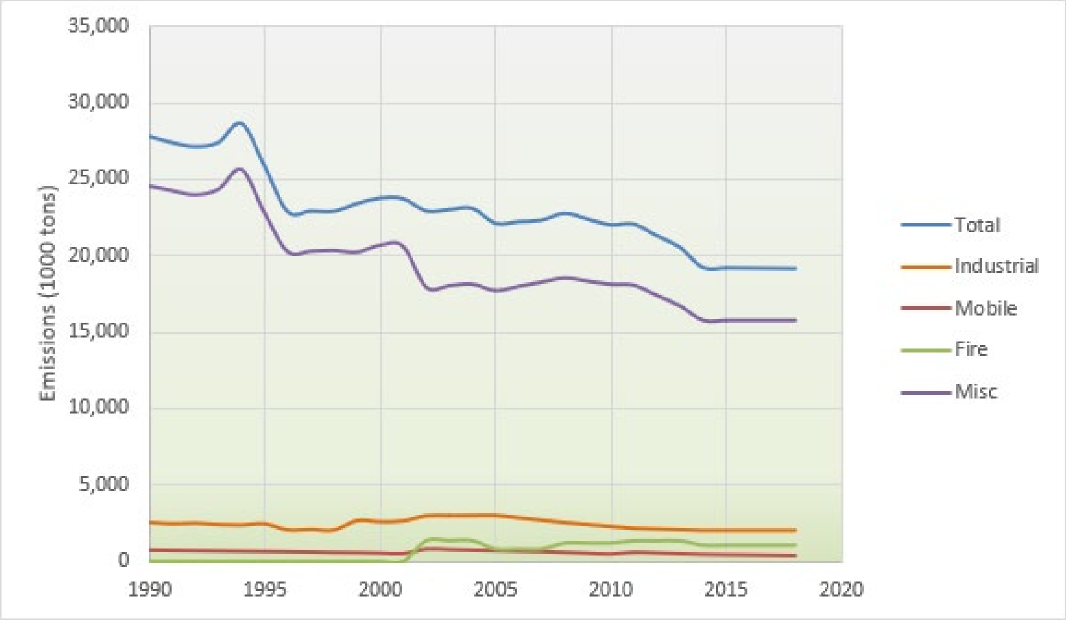
contributor of NO_x emissions originates from on-road vehicles and nonroad engines and vehicles. On-road vehicles include light-duty and heavy-duty gas and diesel vehicles. Nonroad engines and vehicles account for non-road gasoline and diesel engines, aircraft, marine vessels, railroads, and other sources.

Figure 3-2: National NO_x Emissions by Source Group



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 PM_{10} emissions (11% in 2018).***

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



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).

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.[10] 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

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[10] 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

overall decreasing trend. SO_2 and NO_x emissions are marked by less volatility and a more consistent decrease.

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)

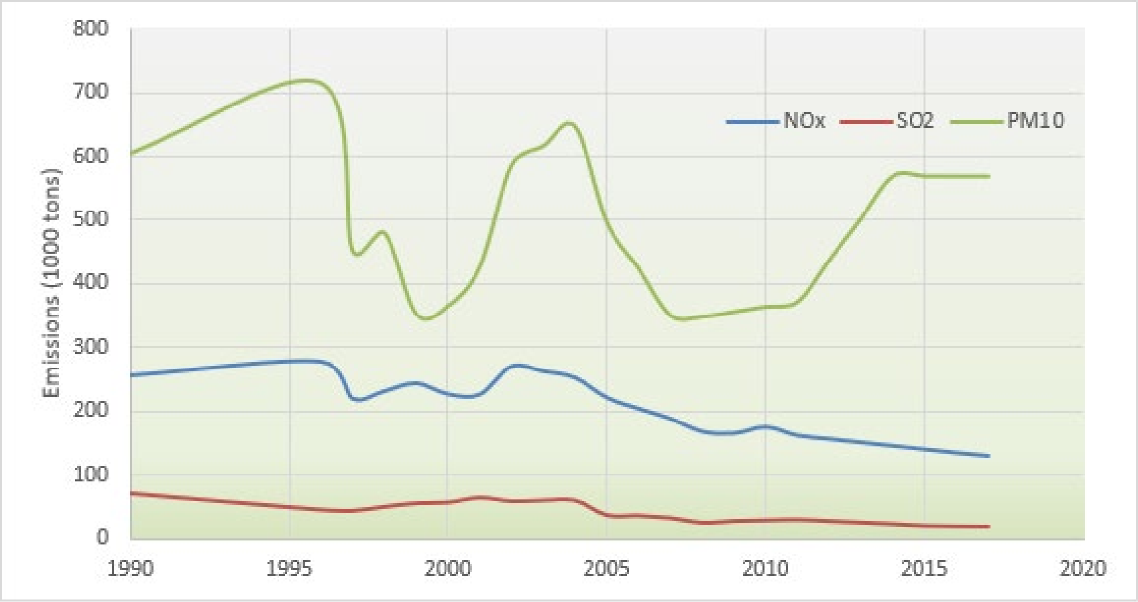
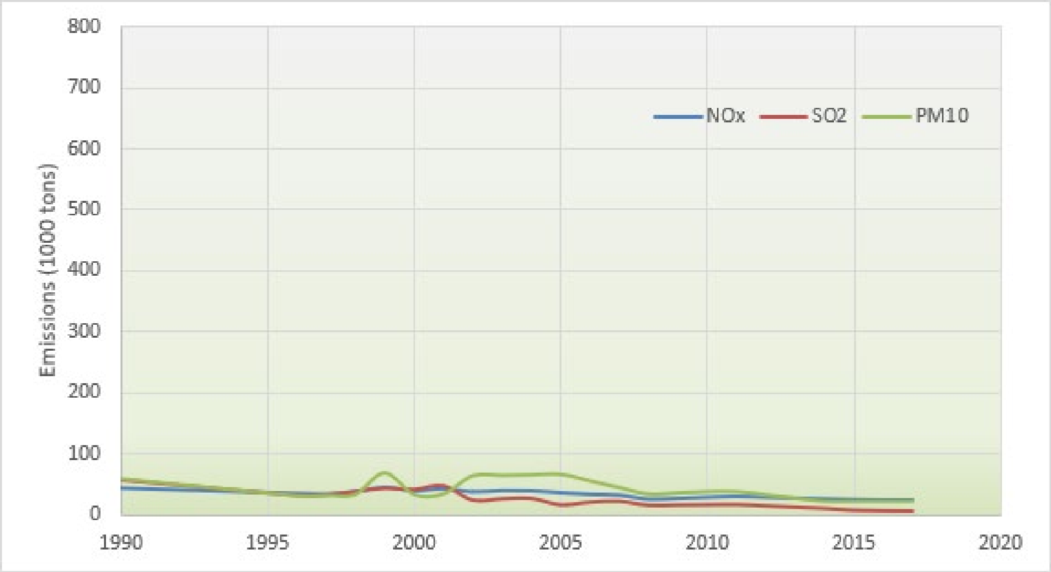


Figure 3-6 provides the industrial emissions data included in Figure 3-4 but in context to the scale of the y-axis in Figure 3-5. This demonstrates the contribution of industrial emissions to total state emissions.

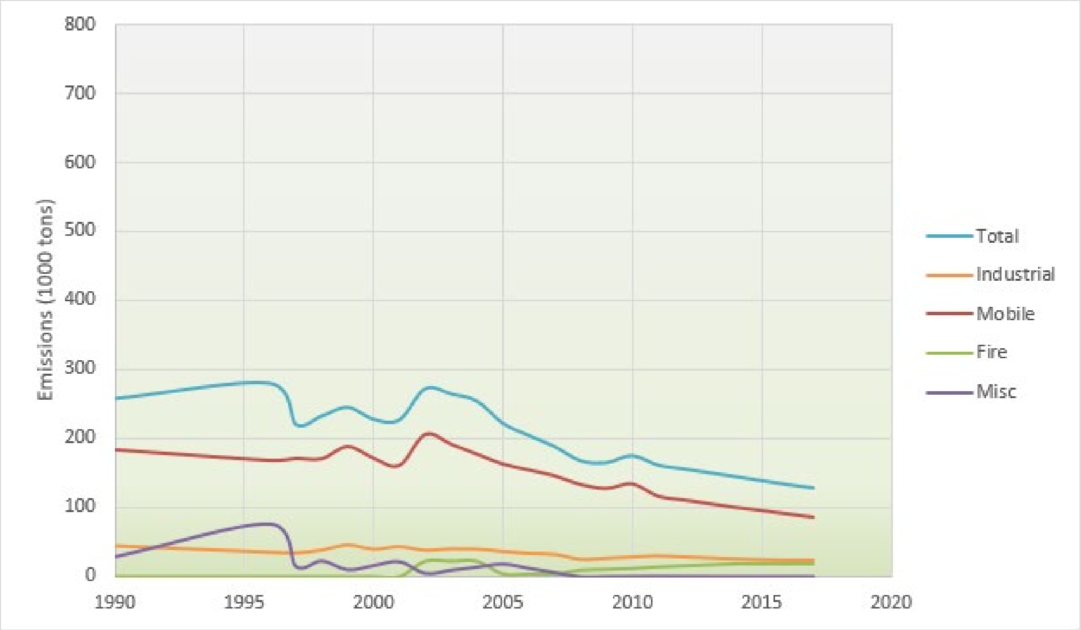
Figure 3-6: Oregon Industrial Emission Trends of PM_{10}, SO_2 and NO_x (1990 – 2017)



As shown in Figure 3-6, industrial emissions account for a very 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.

Figure 3-7: Oregon NO_x Emissions by Source Group



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 mirrors the same trend as the total state-wide emissions and is clearly the largest contributor. However, Figure 3-8 also indicates that wildfires provide substantial PM_{10} emissions to noticeably influence total emissions as shown from 2002 – 2005 and 2008 – 2017.

Wildfire has always impacted the Oregon landscape as it is a natural part of the health and ecology of forests in the region. However, the overall size and occurrence of wildfires in Oregon have increasing in the recent past as indicated in the Wildfire Smoke Trends and Associated Health Risks document produced by ODEQ.[11] The ODEQ Wildfire Smoke document continues to state that these increases are “due to past forestry practices, drought, hotter summers, warmer winters, reduced snowpack, and more human-caused fires.” Ultimately, fire season is now longer than it has been historically. For context, based on the AQI system, Medford, OR has registered 18 days from 1985 – 2014 in the “unhealthy” category. In comparison, there have been 38 “unhealthy” days between 2015 – 2018. The historical influence of wildfire on total regional haze is indicated in Figure 2-1 for the years 2002, 2005, 2017, and 2018. In 2002, the Biscuit Fire burned almost 500,000 acres of the Rogue River-Siskiyou National Forest, accounting for the largest

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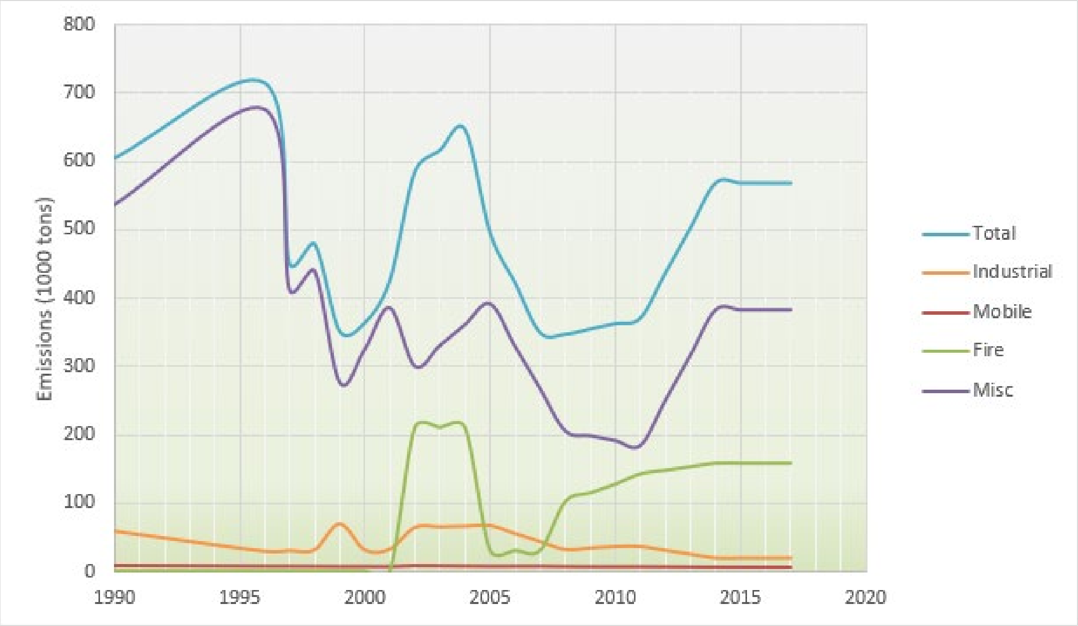
[11] Wildfire Smoke Trends and Associated Health Risks: Bend, Klamath Falls, Medford and Portland – 1985 to 2018 (ODEQ Wildfire Smoke document): https://www.oregon.gov/deq/FilterDocs/smoketrends.pdf

wildfire Oregon recorded history. In 2005, The Blossom Complex fires and Simpson Fire impacted the area and regional visibility. Likewise, the Chetco Bar Fire burned roughly 190,000 acres of the Kalmiopsis Wilderness, and a Brookings wind effect aided in the spread of the fire to within five miles to the north of Brookings, OR. The 2018 wildfire season included five fires within the region, including the Hendrix, Miles, Klondike, Taylor Creek, and Garner Complex fires. While wildfire impact and influence are not included in the assessment of anthropogenic visibility impairment within the Regional Haze program, it is important to note the size, scale, and influence of wildfires on regional emissions and overall visibility impacts. The recent increase in wildfire size and occurrence is indicated by the data trends in Figures 2-1 and 3-8.

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



As discussed in the national emissions evaluation, it is 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 (i.e., industrial source emissions) would intuitively result in diminishing return or outcome on visibility improvement compared to a reduction to a larger contributing factor (i.e., 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."***[12]

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

3.3 PWL 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 PWL's emissions as appropriate candidates for additional control under the reasonable progress criteria.

Current emissions from the PWL hogged-fuel boiler, dryers, and presses are standard for the facility and are not expected to increase during the foreseeable future. Conversely, PWL is continually striving to improve operational efficiency to improve production and reduce emissions. This is further discussed in Section 4.3. Therefore, PWL has concluded that the current baseline emissions of PM_{10}, SO_2 and NO_x selected from the 2017 NEI database are a reasonable estimate for the ongoing emissions from the facility for the purposes of RHR analyses.

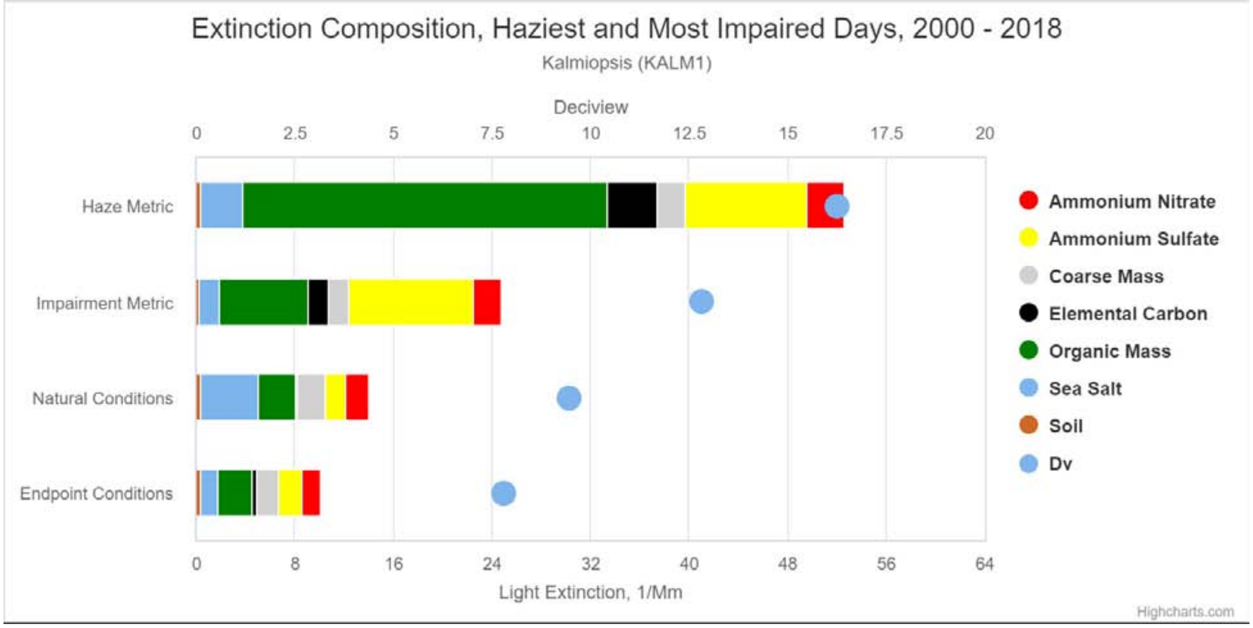
3.4 Emissions vs Visibility Impairment Analysis

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 PWL facility sources. This analysis relies on actual visibility data collected at the Kalmiopsis Wilderness.

As previously shown in Figure 2-1, IMPROVE monitoring shows that the primary pollutant accounting for the most anthropogenic (human-caused) visibility degradation is ammonium sulfate [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.

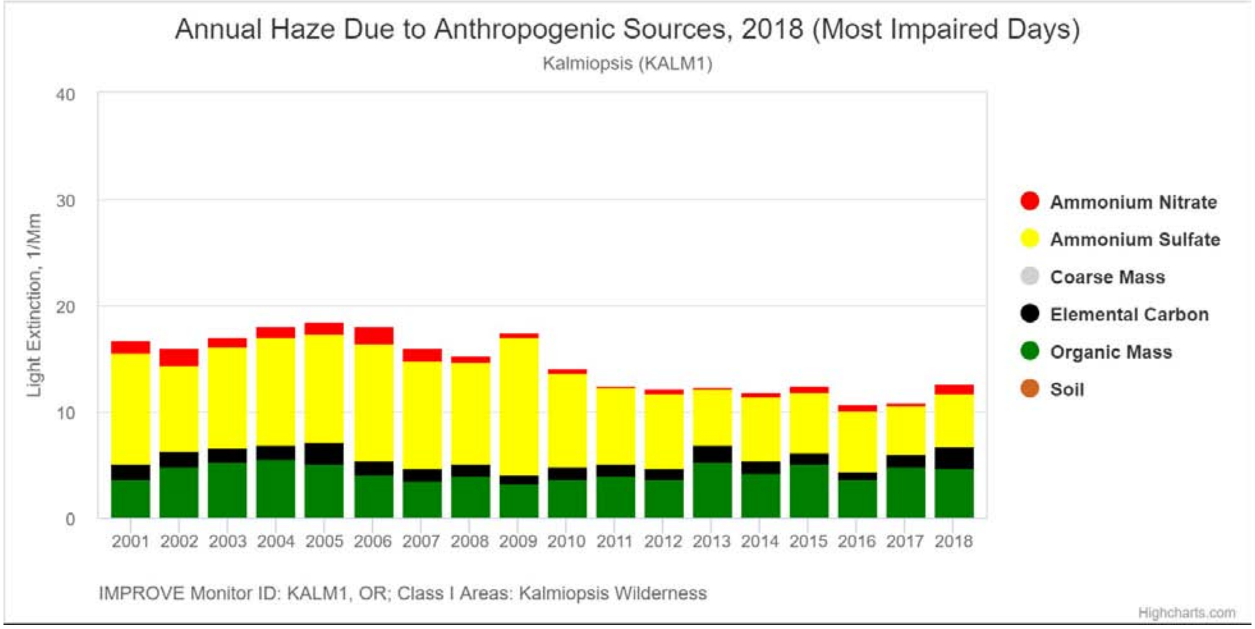
Figure 3-9 indicates a similar representation of haze and impairment contributions by providing the extinction composition by deciview for each metric [6]. Clearly, organic mass dominates the haze metric while ammonium sulfate provides the majority of the impairment metric. As stated previously, visibility degradation caused by anthropogenic (human-based) sources is defined as “impairment”. Organic mass is the second largest contributor to impairment as indicated by Figure 3-9. However, it is important to note that ammonium nitrate accounts for a minimal contribution to anthropogenic impairment. PWL is a source of precursor emissions of organic mass (PM_{10}) and ammonium nitrate (NO_2) but is not a large contributor of any precursors to ammonium sulfate formation (SO_2).

Figure 3-9: IMPROVE Extinction Composition for Kalmiopsis Wilderness



Additionally, Figure 3-10 illustrates annual impairment composition in the Kalmiopsis Wilderness. Again, ammonium sulfate provides the largest contribution to anthropogenic visibility impairment.

Figure 3-10: IMPROVE Annual Haze Composition Due to Anthropogenic Sources for Kalmiopsis Wilderness



4.0 PACIFIC WOOD LAMINATES PERSPECTIVE

4.1 Facility Information

PWL owns and operates a plywood and laminated veneer lumber manufacturing plant (facility) in Brookings, Oregon. The facility is regulated under the ODEQ Title V Operating Permit Number 08-0003-TV-01 which was renewed on December 30, 2019.

As described in the Title V Permit Review Report, the facility produces plywood and laminated veneer lumber. The facility imports the veneer from other facilities and does not process logs. Steam generation from the hogged-fuel boiler provides heating for the veneer drying process and the plywood presses. The hogged-fuel boiler utilizes some sander dust and ply trim for fuel; however, most of the woody biomass fuel (hogged fuel) is imported from other plants. PWL produces approximately 85% plywood and 15% laminated veneer lumber. The emissions from the manufacturing processes are the same for plywood and laminated veneer lumber. Laminated veneer lumber also enters a secondary process on-site which includes finger jointing, molding cutting, edge gluing and painting.

4.2 Facility Location

The PWL facility is located in the city of Brookings, Oregon at 819 Railroad Avenue. The facility boundary is within approximately 0.2 kilometers (km) of the Pacific Ocean coastline and approximately 8.5 km from the boarder with the State of California. The Universal Transverse Mercator (UTM) coordinates for the site are Zone 10, Easting 393,381 meters (m), and Northing 4,656,157 m[13]. The facility is at an elevation of approximately 30 m above mean sea level.

Oregon has 12 Class I areas. The closest Class I airshed to the PWL facility is the Kalmiopsis Wilderness which lies 23.5 km northwest of Brookings, Oregon. Figures 4-1 and 4-2 shows the facility location in relation to the Kalmiopsis Wilderness Class I area. Figure 4-3 indicates the location of PWL to the Kalmiopsis Wilderness as well as the 2017 Chetco Bar Fire impact area.

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

Figure 4-1: PWL Proximity to Kalmiopsis Wilderness Area

Figure 4-2: Facility Location in Oregon

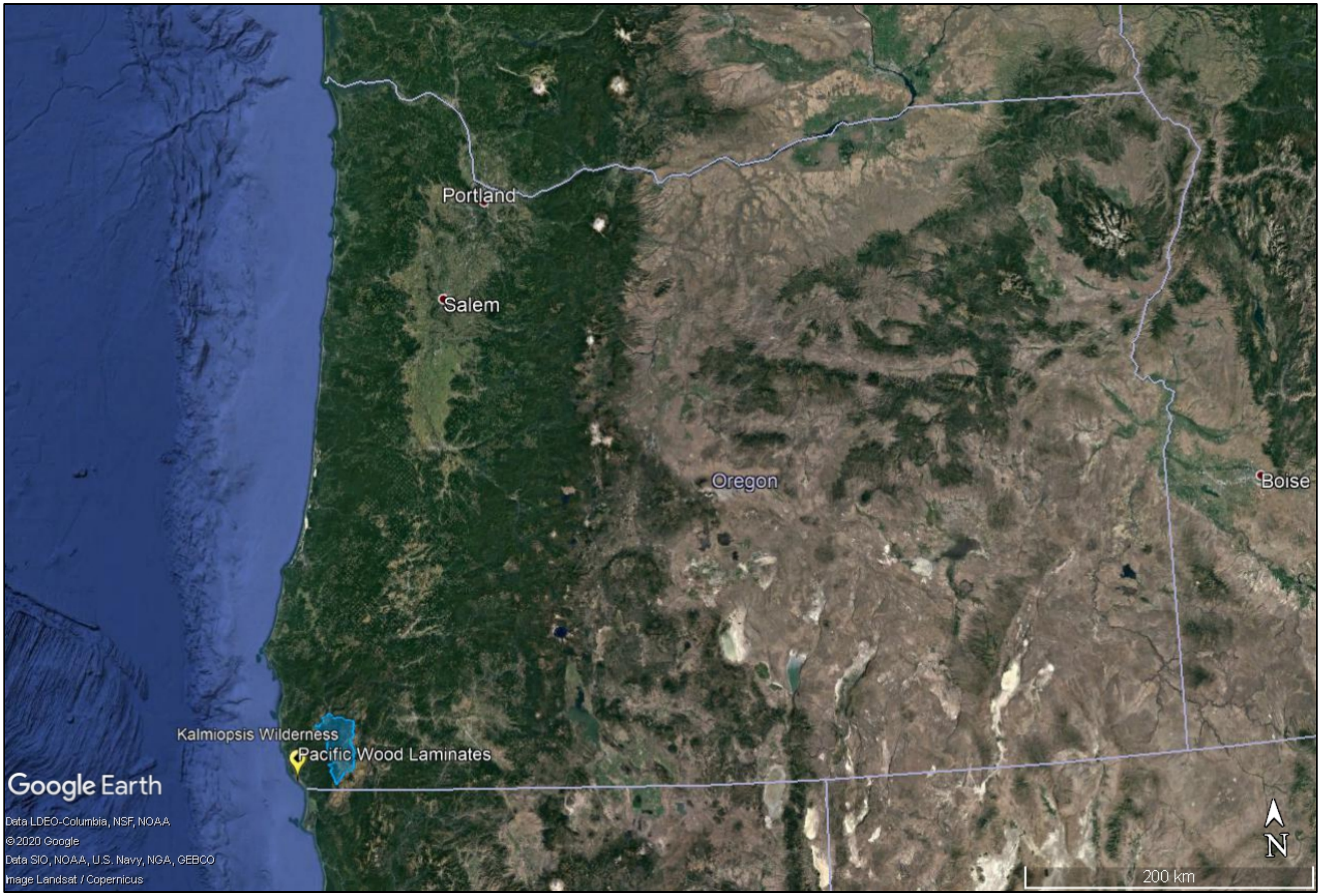
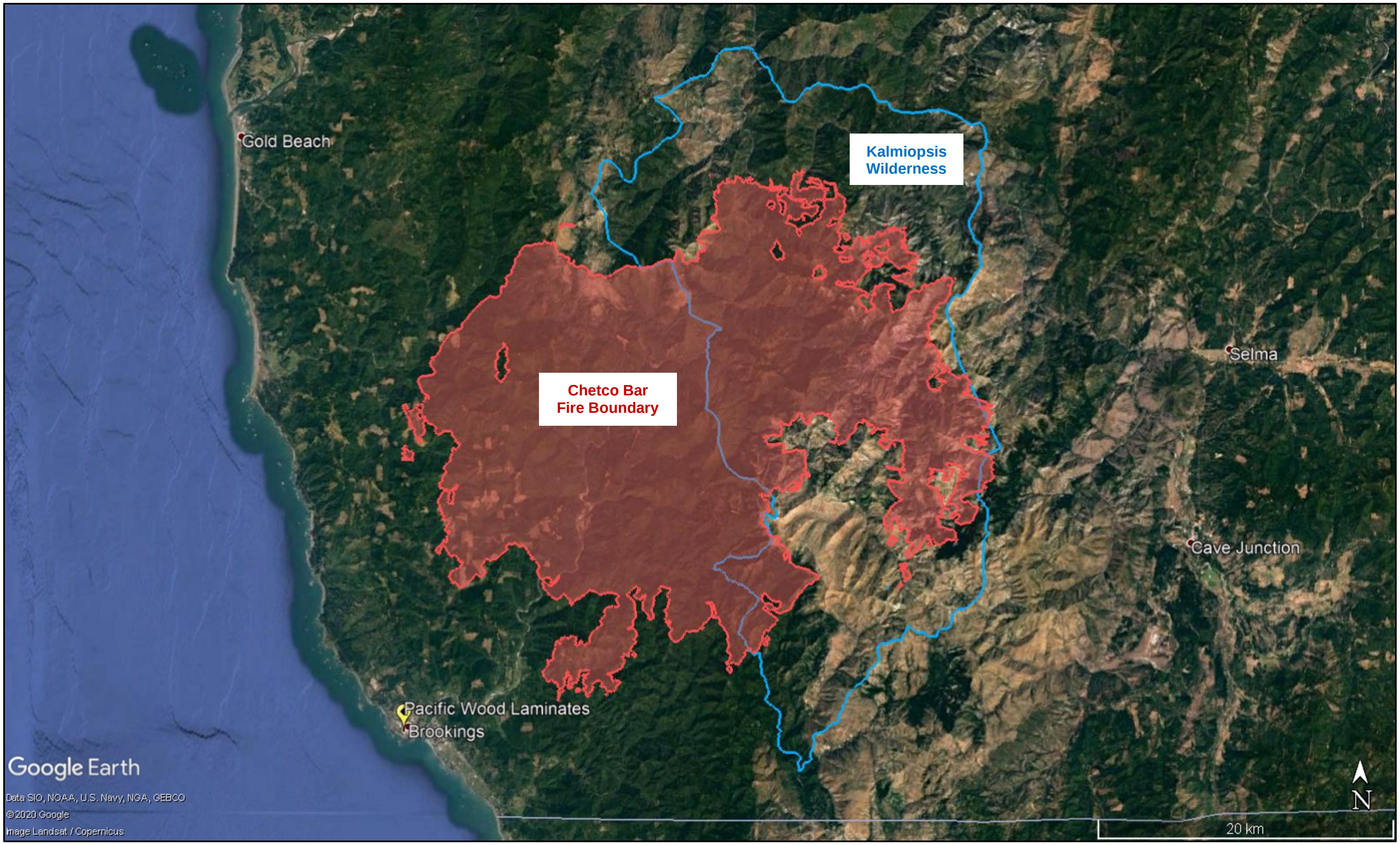


Figure 4-3: PWL Proximity to Kalmiopsis Wilderness Area with Chetco Bar Fire Impact Area



4.3 Historical Facility Upgrades

PWL has taken the initiative to implement multiple upgrades and improvements to the manufacturing plant within the past 20 years. Significant costs have been invested into the facility to increase employee safety, improve efficiency, decrease emissions, and modernize the facility. These facility improvements were completed in good faith by PWL in order to operate a safe and healthy facility for their workers and community. PWL is providing a summary of the projects and upgrades made to the facility to indicate the effort put forth in improving the facility and reducing its impacts. It also demonstrates the experience PWL's management has in developing and understanding the scope of projects within their facility and geographic location.

A summary of the more recent improvements to the facility include:

The modernization and major maintenance of Dryer "C"

- Work performed: 2004 – 2005
- These upgrades included a new veneer feeder, rebuilding of the dryer main fans, new door skins, new door seals, and steam/condensate lines.

The modernization and major maintenance of Dryer "B"

- Work performed: 2008
- Dryer doors were completely rebuilt, as well as the dryer roof, and door seals were replaced.

Major maintenance of the Riley Hogged-Fuel Boiler (PH2) Multi-clone and installation of new Induced Draft Fan (I.D. Fan)

- Work performed: Winter 2012, Spring 2013, and Spring 2015
- This included the complete overhaul and re-tubing of the multiclone.

Replacement of the Plywood Press #4

- Work performed: 2017
- Press #4 was replaced with a modern, SparTek plywood press to improve efficiency and reduce emissions

Installation of a regenerative thermal oxidizer (RTO)

- Work performed: 2018
- The RTO was installed to control emissions from the veneer dryers heated zones and removal of wet scrubbers (WS 1, WS3, WS4).

Construction of new maintenance shop

- Work performed: 2018
- Provides improved enclosure and containment for maintenance activities at facility

Conversion of the RTO to a regenerative catalytic oxidizer (RCO)

- Work performed: 2019

- Upgraded the RTO with the addition of precious metal catalyst to provide better control efficiency to process

Upgrades to the hog fuel handling system

- Work performed: 2018-2019
- Upgrades to the fuel handling system include removing of the Wellons Fuel Silo and the hog fuel return conveyor, the bypass loading station, and the fuel bin out feed. All conveyors are now covered or inside the new fuel house building.

Boiler Fuel Bin Improvements

- Work performed: 2015 to Current.
- Fully enclosed the dry fuel chip bins and installed a negative air system to pull all the particulate into a cyclone and transfer it to another walking floor bin, which feeds fuel to the hogged-fuel boiler.

Boiler Steam Reduction and Energy Conservation Program

- Work performed: 2014 – Present & Ongoing
- This program includes multiple assessments of hogged-fuel boiler operations to ensure the boiler is firing correctly and efficiently. Controls were updated along with operational methodology. A new controls platform was installed along with a tailored PLC Control Logics program. This increased boiler operational efficiencies and operations. Total steam flow from 2019 equivalates to only 75% of the total steam flow produced in 2014. This demonstrates the improvement in boiler operation efficiencies.

Veneer Plant Replacement Project (South Coast Lumber)[14]

- Work performed: 2011 – Present
- Green-end veneer facility replacement to upgrade efficiency and recovery of log to veneer. South Coast Lumber Co. (SCL) is the parent company to PWL. It controls funding and investing at PWL while also providing it with green-end veneer materials. PWL uses the veneer infeed to make plywood and LVL products. The veneer material is the largest cost contributor to making plywood, so the replacement of the facility was a commitment by ownership for continuous improvements at both facilities since it would increase efficiency at both PWL and SCL. Since funding is controlled by the same ownership, it is included in this analysis.

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[14] South Coast Lumber Co. is the parent company to PWL. It controls funding and investing at PWL while also providing it with green-end veneer materials. PWL uses the veneer infeed to make plywood and LVL products. The veneer material is the largest cost contributor to making plywood, so the replacement of the facility was a commitment by ownership for continuous improvements at both facilities. Since funding is controlled by the same ownership, it is included in this analysis.

As previously stated, these upgrades and improvements to the facility were completed by PWL to optimize process efficiency and for internal improvements to employee health and safety at the facility. Costs accrued for the projects are included in Table 4-1. The historical investments and improvements to the facility should not be overlooked.

Table 4-1: Historical Facility Improvements and Costs

Improvement	Approx. Cost ($)
Dryer B and C Modernization	3,075,000
PH2 Boiler and Multiclone Upgrades	85,000
Press #4 Replacement	2,960,000
RTO Installation	2,842,000
Conversion to RCO	166,000
New Maintenance Shop	3,825,000
Fuel Handling Upgrades (Includes fuel bin)	4,227,000
PH2 Boiler Efficiency Program	306,600
Veneer Plant Replacement	5,634,000
Total CIP	**$ 23,120,600**

4.4 Facility Emission Sources

Existing emission sources at the PWL facility are characterized in Table 4-2. This represents all emission units regulated by Title V permit 08-0003-TV-01. The associated emission unit ID (EU ID) and pollution control device is also included in the table. Currently, the hogged-fuel boiler is controlled by a multiclone and two wet scrubbers while the veneer dryers are controlled by an RTO/RCO. Additionally, there are four baghouses throughout the facility to control particulate emissions from various conveyance/pneumatic processes.

Table 4-2: PWL Emission Units and Controls

EU ID	Emissions Unit	Pollution Control Device/Practice	Controlled Pollutant
PH2	Hogged-fuel boiler	Multiclone Wet Scrubbers 1&2	PM/PM_{10}/$PM_{2.5}$
MT	Material Transport: Hog fuel truck unloading, hog fuel pile and boiler feed conveyors, truck loading plytrim, sawdust and sander dust	None	N/A
Presses	Plywood Press 1 Plywood Press 2 Plywood Press 3 Plywood Press 4	None	N/A

EU ID	Emissions Unit	Pollution Control Device/Practice	Controlled Pollutant
CON	Pneumatic Conveyors group: Sander dust Cyclone (Baghouse 1) LVL Plytrim Cyclone (Baghouse 2) Hog fuel handling Cyclone (Baghouse 3) Primary plytrim cyclone (Cyclone 1/Baghouse 4) Glue mixer exhaust fan	Baghouse 1 Baghouse 2 Baghouse 3 Baghouse 4	PM/PM_{10}/$PM_{2.5}$
Dryers	Veneer Dryers: Dryer A Dryer B Dryer C	Regenerative Thermal Oxidizer/ Regenerative Catalytic Oxidizer	VOCs
WE	Unpaved Roads	Watering	PM/PM_{10}/$PM_{2.5}$
VOC	Facility VOCs	None	N/A
AI	Aggregate insignificant activities: Radiant propane heater Maintenance shop raw materials and solvents	None	N/A

As stated in Section 1.2, 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 source of SO_2, NOx and PM_{10} emissions at the facility is the hogged-fuel boiler. The boiler accounts for 97% of facility-wide NOx emissions and therefore is being evaluated for NOx through a four-factor analysis. PH2 also accounts for 77% of facility wide SO_2 emissions. However, the PWL facility has minimal SO_2 emissions in total at 4.3 tpy with PH2 contributing only 3.3 tpy. The remaining 23% accounts for 1.0 tpy from aggregate insignificant sources and 0.001 tpy from the RCO. Therefore, no additional sources are evaluated for NOx or SO_2 since PH2 accounts for nearly all corresponding gaseous emissions from PWL.

The primary sources of PM_{10} emissions at PWL are the Riley hogged-fuel Boiler, the veneer dryers, and the plywood presses. They account for 32%, 16%, and 16% of facility-wide emissions, respectively. Additional sources of PM_{10} at the facility include various material transfers and conveyors, sources controlled by baghouses, vehicle travel on unpaved roads, and an aggregation of insignificant sources. None of these additional sources were considered for evaluation by the four-factor analysis because they account for minimal emissions of facility-wide PM_{10} at 0.7 – 9.0 tpy or 0.5% - 7% of total emissions. Additionally, fugitive sources have minimal loft and lack dispersion characteristics to impact a Class I area 23.5 km from the facility.

Therefore, sources with emission contributions substantive enough for consideration of the four-factor analysis evaluation include the hogged fuel boiler, Plywood Presses 1 – 4, and Veneer Dryers A, B, and C. A further analysis and selection of sources is included in the following subsections.

4.4.1 Riley Boiler, PH2 – Selected for Four-Factor Analysis

The hogged-fuel boiler (PH2) at PWL is a Riley stationary grate stoker and water tube boiler. The boiler was initially commissioned by Louisiana-Pacific (LP) in 1969 at the LP mill in Wenatchee, WA. It was moved to Brookings and installed at PWL in 1986. The boiler utilizes hogged fuel as well as sander dust injection to produce steam. It is situated at the facility next to the old, decommissioned Brookings Plywood Dutch-oven boiler 1 (PH1) providing limited space for additional installation or retrofit. As previously stated, boiler PH2 is currently controlled by a multiclone and two wet scrubbers.

The Riley hogged-fuel boiler PH2 was selected as the only source to be evaluated by four-factor analysis because it is the largest contributor of NOx, SO_2, and PM_{10} at the PWL facility. It is evaluated for the additional control of emissions of PM_{10} and NOx. SO_2 is not evaluated because of negligible total SO_2 emissions. Woody biomass fuel is naturally low in sulfur and SO_2 emission controls are typically not used on wood-fired boilers. Any add-on control to further reduce SO_2 emissions would be cost-prohibitive due to the small amount of pollutant that would be controlled. Therefore, the hogged-fuel boiler is evaluated by four factor analysis for emissions of PM_{10} and NOx in Sections 5 and 6.

4.4.2 Plywood Press Exclusion

Plywood presses emit fugitive emissions of VOC and PM_{10} as sheets of wood veneer are pressed together using hot platens; they do not emit NOx or SO_2. Plywood assembly operations are located within a single large building among other sources of emissions. Because plywood presses are co-located with other process units, it is likely that the limited plywood press emissions data that have been collected by the National Council for Air and Stream Improvement (NCASI)[15] also includes fugitive emissions from other different types of process units in the same building. Nevertheless, estimated total plywood press PM_{10} emissions are minimal at ~22 tpy.

Plywood manufacturing facilities are subject to the NESHAP for Plywood and Composite Wood Products (PCWP) in 40 CFR 63, Subpart DDDD. Although veneer dryers are subject to standards, EPA determined that emissions from plywood presses were not amenable to capture and control and did not set any standards for these sources. EPA distinguished emissions control requirements for plywood presses from other reconstituted wood products presses (e.g., particleboard, OSB, and medium density fiberboard) “because of different emissions characteristics and the fact that plywood presses are often manually loaded and unloaded (unlike reconstituted wood product presses that have automated loaders and unloaders).”[16] By virtue of issuing emission control standards for reconstituted wood products presses only, EPA effectively determined that emissions capture and control is practicable for these types of presses,

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[15] NCASI is an association organized to serve the forest products industry as a center of excellence providing unbiased, scientific research and technical information necessary to achieve the industry’s environmental and sustainability goals.

[16] EPA, “National Emission Standards for Hazardous Air Pollutants for Plywood and Composite Wood Products Manufacturing– Background Information for Final Standards.” February 2004.

but not plywood presses. In the September 2019 PCWP NESHAP risk and technology review proposal, EPA did not propose to add standards for plywood presses.

Additionally, the RACT/BACT/LAER Clearinghouse (RBLC) includes no entries for plywood presses with add-on emissions controls. EPA’s database of emission sources that was developed for the risk and technology review of the PCWP NESHAP indicates that no plywood presses at HAP major sources are enclosed or controlled. We are aware of one minor source (Freres Lumber) that installed a partial enclosure and a biofilter to control formaldehyde and methanol emissions to reduce HAP emissions below major source levels and avoid coverage under the PCWP NESHAP, but they are the only facility that has any emissions controls on a plywood press, and the biofilter is not in place to control PM_{10} emissions.

Plywood presses are fugitive sources whose emissions pass through the building roof vents above the presses. Existing vents in the vicinity of these process units are not intended to quantitatively capture and exhaust gaseous emissions specifically from the plywood presses; rather, they are strategically placed to exhaust emissions from the building. When the process and building ventilation layouts were designed, the possibility of emissions capture or testing was not contemplated.

Plywood presses are not enclosed because they need to be accessed by employees. Plywood manufacturing facilities typically have one layup line that feeds multiple presses. On the layup line, layers of dried veneer are laid down in alternating directions with resin applied between each layer. At the end of the line, the layered mat is trimmed, stacked, and moved to the press infeed area for each press. This configuration requires more operating space and manual input than other wood products manufacturing processes. Plywood presses are batch processes and loading the press is manually assisted (the press charger is manually loaded). Operators must be able to observe press operation to check that the press is properly loaded. Pressed plywood is removed from the area using a forklift. Adding an enclosure to capture emissions is not feasible because it would disrupt operation of the press (both infeed and outfeed), inhibit maintenance activities, and create unsafe working conditions for employees (isolation, heat, emissions, and exposure).

There are no technically feasible controls to reduce plywood press PM_{10} emissions due to the infeasibility and unsafe risk of control and capture. Therefore, the four-factor analysis is not evaluated.

4.4.3 Veneer Dryer Exclusion

Veneer dryers A, B, and C are used to dry thin sheets of wood (veneer) that will be used to make plywood. The first step in producing plywood is to dry the inner veneer plies, or the core of a panel product, to drive moisture out of the material. A suitable moisture content is required in the veneer to provide quality inner plies and to allow for the proper bonding of plywood. Drying veneer is critical to producing a quality plywood product. The veneer dryers at PWL emit PM_{10} and VOCs while drying material. They are also a minimal emitter of NOx (1.75 tpy) and SO_2 (0.001 tpy). The veneer dryers account for approximately 22 tpy of PM_{10} emissions at PWL.

Currently, the veneer dryers are controlled by RTO/RCO to reduce emissions of VOCs and hazardous air pollutants (HAPs). Again, PWL is subject to 40 CFR 63, Subpart DDDD for PCWP. Use of the RTO/RCO maintains compliance with the applicable Maximum Achievable Control Technology (MACT) standards for the veneer dryers. RTO/RCOs are not mandated as a specific requirement for the facility under Subpart DDDD, however PWL installed the Best Available Control Technology (BACT) to guarantee the greatest level of control. RBLC includes entries for veneer dryers controlled by RTO/RCO but includes no entries with add-on emissions controls for PM_{10}. Additionally, RCO is considered Best Available Control Technology for Toxics (TBACT) for controlling toxic air pollutants (TAPs) regulated by the Cleaner Air Oregon program. This provides more indication of PWL's commitment to emissions reductions within other regulatory programs.

The proper operation of the veneer dryers is critical to the quality of material produced at PWL. Add-on controls beyond the RTO/RCO could interfere with the production of the veneer dryers, compromise product quality, or compromise the efficiency of the RTO/RCO. Therefore, no additional control options are evaluated for the veneer dryers. No other facilities have proven the feasibility or necessity in controlling PM_{10} emissions from veneer dryers controlled by RTO/RCO per RBLC and the dryers are a smaller source of PM_{10} at the facility. Therefore, a four-factor analysis is not evaluated.

5.0 FOUR-FACTOR ANALYSIS FOR SO_2 AND NO_X

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 uncontrolled NOx and SO_2 emissions to NOx and SO_2 emissions, individually controlled by respective technologies.

The following sections present the analysis for the PWL Brookings facility using the direction of the EPA Draft Guidance [9] and WRAP four-factor analysis guidance [10]. The initial step in the four-factor analysis was to identify possible additional control options for this source. As discussed in Section 4.4.1 above, the four-factor analysis focused on controls for the PWL hogged fuel boiler.

5.1 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 PWL air quality permit of 0.015 lb/klb. The current actual emissions are calculated based on the average boiler steam production rate for reporting years 2016 – 2019. The average boiler steam production rate was 295,671 klb/yr and current actual SO_2 emissions are estimated as follows:

$$0.015 \text{ lb/klb} * 295{,}671 \text{ klb/yr} \div 2000 \text{ lb/ton} = 2.2 \text{ tpy}$$

The hogged fuel boiler accounts for 77% of SO_2 emissions from the facility with aggregate insignificant activities accounting for the other 23%.

Any add-on control to further reduce SO_2 emissions would be cost-prohibitive due to the small amount of pollutant emitted so a four-factor analysis was not assessed for SO_2 emissions.

5.2 Available NO_x Control Technologies

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

- Combustion modification
- Selective catalytic reduction (SCR)

- Regenerative selective catalytic reduction (RSCR)
- Non-selective catalytic reduction (SNCR)

5.2.1 Combustion Modification

As previously mentioned, the hogged fuel boiler at PWL is a Riley stationary grate stoker and water tube boiler. It was initially commissioned in 1969 and installed at PWL in 1986 with limited space or technical feasibility for retrofit. Combustion controls, such as flue gas recirculation, staged combustion, low NOx burners, and fuel staging are either not compatible with this boiler or do not have high NOx control rates. Hogged fuel also contains some fuel-bound nitrogen that readily converts to NOx, which is not reduced by combustion controls. This fuel-bound nitrogen further reduces the assumed NOx control of the various combustion modifications. Additionally, the boiler utilizes hogged fuel as well as sander dust injection. Control options, such as low NOx burners, are likely not available for the co-firing of sander dust fuel because of likelihood of fouling. Converting the boiler to natural gas is also infeasible because natural gas is not available to the southern coast area. Conversion to propane would not be cost effective.

5.2.2 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. NOx 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 NOx decomposition reaction. Technical factors that impact the effectiveness of SCR include inlet NOx concentrations, catalyst reactor design, operating temperatures and stability, fuel type and sulfur content, design of the ammonia injection system, catalyst age and reactivity, and the potential for catalyst poisoning [11].

SCR is not widely used with wood fired combustion units because of the amount of particulate that is generated by the combustion of wood. When the combustion source is a biomass-fired boiler, the SCR must be placed downstream of the particulate control equipment for proper operation. However, the particulate – if not removed completely – can cause plugging in the catalyst and reduce the surface area of the catalyst available for reaction. The presence of alkali metals commonly found in wood, such as sodium and potassium, will irreversibly poison catalysts. Other naturally occurring catalyst poisons found in wood are phosphorous and arsenic. In order to prevent the plugging, binding, and/or poisoning of the SCR catalyst, it is necessary to first remove particulate from the exhaust gases. However, it is not considered technically feasible to place a SCR unit upstream of the particulate control device in a wood-fired boiler or burner application because of the SCR flue gas temperature requirements.

SCR control technology works best for flue gas temperatures between 575°F and 750°F and is typically installed upstream of any particulate control equipment where the temperature is high enough to support the process. 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 hogged fuel boiler show an average stack exit temperature of approximately 490 - 500ºF.

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 RBLC database. For the reasons stated in this section, PWL considers this alternative technically infeasible, and SCR is eliminated from any further consideration as a feasible control technology.

5.2.3 Regenerative Selective Catalytic Reduction

RSCR is a commercially available add-on control technology by Babcock Power Inc. that combines the technology of a regenerative thermal oxidizer device and SCR. Ammonia is injected upstream of the catalyst just as with a traditional SCR unit, and the reactions between ammonia and NO are the same. The control equipment is intended to be placed downstream of emission control systems where the exhaust gas is clean, but the temperature is below the optimal temperature range for catalytic reduction of NOx. Therefore, the RSCR unit has a front-end preheating section that reheats the exhaust stream with a regenerative thermal device. The exhaust is heated to a temperature in the range optimal for catalytic reduction (600°F to 800°F) prior to entering an SCR unit.

The RSCR units were being heavily marketed in 2011 but concerns across the air pollution control industry relating to the catalyst performance, unit cost, and thermal efficiency inhibited widespread adoption. RSCR vendors have not guaranteed catalyst life beyond three years due to the potential for poisoning and blinding associated with the combustion products of wood fuels. It is known in the wood products industry that catalyst media becomes poisoned, plugged, or quickly destroyed in particulate laden biomass direct fired applications.

No BACT determinations for RSCR units have been made in the past 10 years for control of NOx emissions from units combusting wood, wood products, or biomass. Therefore, RSCR unit is not technically feasible for wood combustion units and is eliminated from any further consideration as a feasible control technology

5.2.4 Selective Non-catalytic Reduction

SNCR drives the noncatalytic decomposition of NOx 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 NOx emissions may result [12].

Removal efficiencies of NOx vary for SNCR, depending on inlet NOx 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 hogged fuel-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 potential feasibility 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 hogged fuel boiler.

5.3 Current Actual NOx Emissions and Post-control NOx Emissions

Current NOx Emissions

The hogged fuel boiler is not currently equipped with NOx control, nor are there any permit limits on NOx emissions from the boiler. For setting the baseline for this analysis, the results of a June 11, 2019 source test were used for the inlet NOx rate. The average result from the tests is 0.2458 lb NOx per MMBtu. The higher heating value of the fuel is 17,480,000 btu per bone dry ton (BDT) based on Title V permit 08-0003-TV-01. Estimated actual annual fuel consumption is calculated at 27,883 BDT per year based on a four-year average of fuel input from 2016 – 2019. These values allow for the calculation of annual emissions as follows:

0.2458 lb NOx/MMBtu * 17.48 MMbtu/BDT * 27,883 BDT/year * 1 ton/2000 lb = 59.9 tpy

PWL operates 8,064 hours per year as stated in 08-0003-TV-01. That equates to 14.9 lb/hr of NOx emissions.

SNCR Controlled NOx Emissions

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 NOx, the NSR ranges between 0.5 and 3. Figure 1.7 in the Control Cost Manual shows the effect of the NSR on NOx reduction. Just above the figure, the Manual states, "Increasing the quantity of reagent does not significantly increase the NOx 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 which is an undesirable by-product that is discussed in Section 5.6.

Based on Equation 1.17 and an upper bound of 2.0 for NSR, the estimated achievable NO_x reduction in the boiler is 41%. This estimated NOx reduction is reasonable, and possibly even optimistic, given the relatively low inlet NOx emissions from the boiler. The controlled NOx emission rate is calculated as follows:

0.2458 lb/MMBtu * (1 - 0.41) = 0.1450 lb/MMBtu

Again, this reduction is based on the upper bound NSR to prevent ammonia slip based on Equation 1.17. This would result in approximately 35.3 tpy and 8.8 lb/hr of NOx emissions.

5.4 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]. Additional cost information is provided by the SNCR vendor (Wellons), KH2A Engineering, Arctic Engineering, and PWL. A printout of the completed spreadsheet is included in Appendix B along with supporting information. The vendor quote used in the analysis is included in Appendix D.

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 PWL's hogged fuel boiler 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 as listed in 08-0003-TV-01. Additionally, the four-year average from 2016 – 2019 was used to estimate actual annual fuel consumption in BDT per year. These values are previously discussed in Section 5.3.

5.4.1 SNCR Data Inputs

The combustion unit is an existing industrial boiler so the addition of an SNCR is classified as 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 although the modification is expected to be more difficult than average (EPA provides little guidance with respect to the retrofit factor). The complications in the modification/retrofit are instead addressed directly by PWL and accounted for in the cost evaluation spreadsheet and this section. Therefore, other capital outlay based on boiler modifications, civil engineering, control monitoring, and earthquake design are accounted as individual costs rather than through the use of the retrofit factor.

The fuel type box in the cost spreadsheet is blank because no default fuel information was used. Instead, a net plant heat input rate (NPHR) was calculated based on wood biomass. The boiler heat input rate is 86 MMBtu/hr and the HHV of the hogged fuel is 17,480,000 Btu per BDT based on 08-0003-TV-01. Actual annual fuel consumption is estimated to be 27,883 BDT/yr for the boiler based on a four-year average (2016 – 2019). The NPHR was calculated at 17.5 million Btu per megawatt-hour (MMBtu/MWh) based on the conversion of 1.0 BDT/MW [17]. The NPHR was calculated as follows:

17,480,000 Btu/BDT * 1 BDT/MW * 1 MMBtu/10^6 Btu = 17.5 MMBtu/MW

Inlet NOx emissions to the SNCR are 0.2458 lb/MMBtu based on the average NOx emissions measured at the two wet scrubbers during a June 11, 2019 stack test. A removal efficiency of 41% is assumed as explained above due to the NSR. A corresponding outlet NOx emission rate from the SNCR equates to 0.145 lb/MMBtu.

An SNCR system using urea injection was selected based on the Wellons quote. The default reagent values in the EPA spreadsheet for urea were utilized as no specific values were provided from the vendor.

Cost values are based on the 2019 Chemical Engineering Plant Cost Index (CEPCI) value of 607.5, based on the annual average [14].

The currently published prime rate of 3.25% was used as the annual interest rate.[17] PWL operates under the fiscal and managerial structure of South Coast Lumber (SCL). Financing of projects is procured through SCL at their chosen interest rate and financial discretion. PWL notes that the interest rate for any project financing would likely be greater than the current bank prime rate and is not necessarily reflected accurately in the analysis. However, PWL also acknowledges the use of the prime rate to standardize all Round 2 four-factor analyses in Oregon. So, this analysis utilizes the bank prime rate at the request of ODEQ guidance.

An estimated equipment life of 20-years is utilized for the SNCR per the EPA Control Cost Manual. PWL acknowledges that ODEQ requests a 30-year expected life, however the EPA Control Cost Manual applies a 20-year equipment life to retrofit SNCR which appropriately supports this analysis. PWL believes the actual equipment life will likely be in the 10 to 12-year range due to the local climate. The coastal location of the PWL facility in southwest Oregon provides exposure to heavy rainfall, ocean fog, and sea spray. Existing equipment at the facility is painted annually to prevent corrosion and protect from rust and degradation. Fuel systems and chip bins are often re-skinned to prevent degradation. Figure 5-1 provides an example of equipment corrosion from extreme weather conditions. The photograph shows support steel that had been installed less than 30-years prior. Therefore, the 20-year expected life is utilized in the analysis. A cost effectiveness accounting for 30-years is also included as a footnote to the section.

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[17] Bank prime loan interest rate of 3.25% as of June 8, 2020: https://www.federalreserve.gov/releases/h15/

Figure 5-1: Steel Degradation at PWL Due to Exposure

The fuel cost for the hog fuel was estimated to be $2.00/MMBtu based on an average 2016 price of $32 per bone-dry ton (BDT) delivered [15] (corrected to 2019 dollars using the CEPCI) and a fuel HHV of 8,740 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. The spreadsheet also accounts for 336 days of operation per year as stated in 08-0003-TV-01.

5.4.2 Capital Cost Analysis

PWL consulted Wellons to provide a cost quote for the installation of a SNCR control system to the hogged fuel boiler. It is included in Appendix D. The quote provides a limited capital cost of $800,000 that includes a urea storage tank, system piping, compressed air system, skid, injection nozzles, control panel, software, and mechanical installation. However, it does not include the cost associated with modifying the boiler, site work to accommodate additional equipment, upgrades to the boiler control system, and a continuous emissions monitor system (CEMs).

PWL consulted KH2A engineering and Arctic Engineering to develop additional costs pertaining to the engineering, site preparation, permitting, and installation of the control system. Additionally, PWL has extensive knowledge and familiarity in developing projects at the facility as indicated by the list of recent upgrades and modifications detailed in Section 4.3.

The calculation methodology for SNCR in the EPA Air Pollution Control Cost Manual is somewhat different than the general Control Cost Manual methodology because it does not estimate equipment costs and installation costs separately. Instead, the purchased equipment cost, the direct installation cost, and the indirect installation cost are estimated together.

Therefore, the TCI includes the direct and indirect costs associated with purchasing and installing SNCR equipment. Costs include SNCR equipment, auxiliary equipment, direct and indirect installation, additional costs due to installation, buildings and site preparation, offsite facilities, land, and working capital. The EPA Control Cost Manual spreadsheet aids in calculating the capital cost and balance of plant (BOP) cost. Those costs are summed together and a factor of 1.3 is applied to estimate engineering and construction management costs, installation, labor adjustment for the SNCR, and contractor profit and fees. The PWL analysis expands on the Control Cost Manual methodology and provides specific costs for engineering, construction, and installation instead of utilizing the factor of 1.3. Table 5-1 provides the costs accounting for the TCI of an SNCR system installation to the hogged-fuel boiler. The Wellons quote provides the capital cost of the project. The BOP costs are evaluated using the Control Cost Manual methodology. Instead of the 1.3 factor, the additional costs associated with engineering design, construction, and boiler/facility modification are provided individually and further discussed below.

Table 5-1: SNCR Total Capital Investment Analysis

Expenditure	**Cost**
Capital Cost (Wellons Quote)	$ 800,000
Balance of Plant Cost	$ 523,656
Civil and Structural Engineering	$ 600,000
Site Work	$ 1,800,000
Boiler Modification	$ 3,150,000
CEMs Installation	$ 250,000

The vendor-provided quote from Wellons comprises of the capital costs associated with the project. As previously stated, this accounts for the SNCR and associated equipment. It does not include the cost associated with modifying the boiler, site work to accommodate additional equipment, upgrades to the boiler control system, and a CEMs.

BOP costs are calculated using the methodology within the EPA Control Cost Manual spreadsheet for SNCR. It represents costs categorized within the Control Cost Manual such as auxiliary power modifications, electrical upgrades, and site upgrades typical of the installation of an SNCR unit.

Civil engineering, structural engineering, and site work will be extensive for this hypothetical project due to the current facility layout and the geographical location of the PWL facility. These considerations were evaluated by KH2A and PWL. A lack of available space near the boiler will require an overhaul of the area to accommodate the SNCR system. The current boiler building will require modification and subsequent retrofit to meet current code. Modification to the layout would require the removal of PWL's old

Dutch-oven boiler (PH1) to accommodate the SNCR control unit and auxiliary equipment. Additional upgrades would be required to the fire pump room and the fire suppression system. A fire suppression system is currently buried underground on the west-side of the boiler. A section of that system would likely need to be relocated to accommodate the SNCR system and provide adequate fire suppression.

Additionally, any work to the existing foundation or any new construction (Urea storage tank area and SNCR skid) would require extensive structural design and geotechnical engineering because of the facility's location within the Cascadia subduction zone/fault line. Over-engineering practices are required for new construction due to the location within the fault zone and the facility's proximity to the ocean. Therefore, building costs, concrete, site work, and construction will require substantially more design and material than a general project.

As previously stated, the PWL facility is within 0.2 km of the Pacific Ocean coastline. Applicable seismic and wind loads for this site are high. The seismicity of Brookings is the highest in the entire State of Oregon. Design accelerations specified by the Oregon Structural Specialty Code require 200% of "g" be used for lateral design. The design parameter "g" is the force of gravity downwards, so 200% g acting in the lateral direction is very high seismicity. Design wind speeds for Brookings are also high and vary from 125 to 145 mph depending on the structure Risk Category. Very high seismic and wind loads result in heavier, stronger, and more costly structures and foundations.

The current facility layout and soil structure also provides difficulty in design and construction. The site soil conditions, in and around an old mill pond was filled with material of dubious quality and are prone to liquefaction during significant seismic events. Liquefaction causes the soil grains to rearrange themselves in a fluid fashion. Impacts of liquefaction include soil settlement, loss of soil bearing strength, lateral spreading, and amplified foundation vibration. Mitigation for the liquefaction hazard regarding foundation design includes Code-driven deep foundations (piles or piers deriving their soil bearing strength from embedment in competent soil layers beginning about 20 feet below ground surface). Otherwise, the liquefiable layers would need to be removed and replaced with stronger engineered fill materials. Both methods are costly to execute. Recent projects in this area used conventional footings founded upon the deep competent soil layers. Exact extents of the susceptible soils are not precisely known, adding to the potential uncertainty in design and costs.

Modification to the boiler will also provide challenges given the current configuration at the facility. The installation would require R-stamp tube work as well as sign off for insurance purposes. The boiler would also likely require replacement of a newly sized F.D. and/or I.D. fan as well as a firebox to accommodate effective urea injection and boiler operation. Additional modifications will need to be made to the boiler to ensure proper operation with the SNCR system.

Lastly, the addition of an SNCR would likely require the installation of a CEMs to determine the appropriate injection rate and placement of urea. This helps aid in the overall maintenance of the boiler by preventing degradation from the urea injection and prevents ammonia slip formation.

Collectively these costs equate to the TCI for the installation of SNCR to the hogged-fuel boiler and were further evaluated for cost effectiveness.

5.4.3 Cost Effectiveness Calculation Results

The cost calculation indicates that the addition of SNCR to the hogged fuel boiler would have a cost effectiveness of $30,216 per ton of NOx removed, in 2019 dollars. This value represents the cost of installing and operating SNCR add-on NOx control technology and CEMs in the Riley hogged-fuel boiler. If the boiler were retrofitted with SNCR, approximately 22.6 tons per year of NOx emissions would be eliminated.

Table 5-2: Hogged Fuel Boiler Cost Effectiveness Analysis – NO_x

Control Technology	**% Reduction**	**Emissions (tons/year)**	**Emissions Reduction (tons/year)**
No NOx Control (Base Case)	Base Case	59.9	Base Case
Combustion Modification	Not feasible due to boiler age and design.		
SCR/RSCR	Not feasible due to boiler exhaust characteristics.		
Selective Non-catalytic Reduction	41.0%	35.3	22.6
SNCR Cost Parameters			
Boiler Fuel Consumption Rate	27,883 bone dry tons (BDT) per year		
Fuel Higher Heating Value	17,480,000 Btu per BDT		
Total Capital Investment	$7.1 million		
Total indirect annual costs, including capital recovery	$493,313		
Total direct annual O&M Costs	$160,182		
Total Annual Capital Recovery and O&M Costs	$653,495		
Cost per ton PM10 Removed[18]	$653,495 ÷ 22.6 tpy = $28,912/ton		

5.5 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] PWL estimates that SNCR retrofitting would require approximately 24 - 60 months for design, permitting, financing, etc. through commissioning. This downtime would account for the site preparation and

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[18] Cost per ton in table 5-2 is based on a 20-year expected equipment life. SNCR installation with a 30-year expected life equates to $23,838 per ton NOx removed.

construction surrounding earthquake requirements and soil challenges. Removal of equipment would be required as well as the re-construction and design of existing equipment. Additionally, retrofitting the Riley hogged-fuel boiler with SNCR would require shutting down the boiler for extended periods of time for site renovation and boiler retrofit. PWL does not have an alternative or replacement boiler so production would be stopped indefinitely. Additional profits would be lost, and employees furloughed due to the retrofitting process.

5.6 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. Ammonium sulfate is the leading contributor to visibility impairment (anthropogenic sources) in the Kalmiopsis Wilderness, as discussed in Sections 2.1 and 3.4. Additionally, ammonia slip would potentially provide nuisance odor and visibility impairment locally in Brookings.

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.

PWL is located within approximately 0.2 km of the Pacific Ocean coastline. On-site storage of Urea poses a pollutant discharge risk to the surrounding water table and the coastal ecosystem via contaminated runoff or spill.

5.7 Factor 4: Remaining Useful Life

The Riley hogged-fuel boiler was installed at PWL in 1986 and was originally commissioned in 1969. The boiler has been adjusted and tuned to efficiently operate with the PWL fuel source of coastal grown logs, recovery wood fiber from salvage logs, and sustained yield timber from the Company’s timber lands. Most importantly, the boiler effectively processes residuals from fee timber lands. The remaining useful life of the boiler is considered to be at least the entire duration of the capital recovery period of the cost analysis.

5.8 Technical Feasibility Discussion

Potential difficulties surrounding current facility operations and fuel use could prevent the technical feasibility of retrofitting the Riley hogged-fuel boiler for application of SNCR. These engineering and operational risks are difficult to estimate therefore PWL considered SNCR a potentially feasible option for the four-factor analysis. However, these concerns would only be determined through the retrofit, re-design, and modification process of the boiler which could lead to major operational pitfalls if discovered during the reconstruction process. They are addressed in the section for further consideration towards SNCR application.

Firstly, the hogged fuel boiler will require extensive retrofit as described in Section 5.4.2. This will likely include a new F.D. or I.D. fan and firebox to accommodate for boiler operational adjustment, urea injection, and residence time. However, the difficulties are not solely limited to the mechanics of the boiler. Difficulties also exist surrounding fuel usage requirements for PWL. The boiler fires on both hogged fuel infeed and sander dust injection. SNCR relies on the injection of urea in the combustion chamber which may have negative consequences when combined with the particulate loading from sander dust injection. The facility’s inability to utilize sander dust as fuel would then create issues surrounding waste disposal and winter operational feasibility.

The combustion of sander dust helps prevent waste-product build up at the facility, so it is injected up to 8 or 10 hours a day during boiler operation. The sander dust product builds up and must be burned at the facility because there is no way to landfill the material economically. Without sander dust injection, PWL would be required to haul the material by truck to Medford, OR for disposal, if accepted at the landfill. Additionally, sander dust injection is also essential for operating the boiler during the winter season in Brookings. The hogged fuel can achieve a 50-60% moisture content due to heavy rainfall in the winter. The sander dust injection is necessary to achieve sufficient heat content to dry the hogged fuel infeed and provide boiler combustion. Additional moisture in the winter via urea injection would create a further saturated fuel feed in the winter inhibiting boiler operation. Even more so, SNCR interference or incompatibility with sander dust injection would potentially prevent winter operation of the boiler and greatly increase operational costs at PWL if disposal by landfill were required in place of combustion.

Additionally, proper application of SNCR requires an optimal injection temperature window and residence time for proper control. The location of the desired temperature window will likely change with operational fluctuations and type of fuel feed. PWL processes various species of wood throughout the year and the type of fuel fed into the boiler fluctuates monthly and seasonally. This makes it difficult to determine an accurate and consistent temperature window in the boiler for proper injection. Ammonia slip could then be a recurring problem associated with the application of the SNCR. The existing wet scrubbers would help collect ammonia slip from the effluent stream however it would then prevent PWL from being able to appropriately process the wet scrubber bleed-down water. Currently, PWL is permitted to discharge wet scrubber bleed-down water under a City of Brookings sewer discharge permit. The addition of ammonia would not meet discharge requirements. Thus, PWL would need to determine a method for tracking ammonia concentration from the wet scrubber discharge and determine an alternative method of disposal if necessary.

Due to the above stated risks, PWL believes the installation of SNCR would presumably require the replacement of the wet scrubbers with a dry electrostatic precipitator (ESP) as well. A review of the EPA RBLC database from 2000 – 2020 further supports this presumption. A review of biomass-fired boilers under process type 12.120 (<100 MMBtu/hr) and 13.120 (100 – 250 MMbtu/hr) indicates that only boilers equipped with

SNCR employ ESP for particulate control. No listed boilers utilize wet scrubbers in conjunction with SNCR. If this were the case at PWL then the total capital investment for the removal of the wet scrubbers and the installation and operation of an ESP would need to be included in the cost of SNCR control. An ESP cost analysis is included in Section 6. Additionally, the wet scrubbers currently utilize the wastewater from the dryers. So, if the wet scrubbers were removed to place an ESP and SNCR then PWL would need to construct more water storage and processing system/infrastructure as well.

6.0 FOUR-FACTOR ANALYSIS FOR HOGGED-FUEL BOILER: PM_{10} EMISSIONS

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 as controlled by the existing wet scrubbers and the PM_{10} emissions as controlled by an alternative technology.

The hogged fuel boiler, PH2, is currently equipped with a multiclone to control the bulk of the particulate matter emissions from the boiler. The multiclone is the primary PM emissions control device and is followed two wet scrubbers as secondary control devices. The exhaust from the multiclone split between the two wet scrubbers.

This evaluation will examine the cost effectiveness of replacing the wet scrubbers with a more efficient secondary particulate control device. This provides an “effective” emissions reduction by comparing the currently controlled emission rates from the wet scrubbers to any further reduced emission rate from improved control.

The current actual emissions from the wood-fired boiler are the emissions as controlled by the multiclone and wet scrubber, as discussed in Section 6.2 below.

6.1 Available PM_{10} Control Technologies

A variety of particulate control technologies are available for removing particulate matter from the wood-fired boiler exhaust. The available types of control devices are listed below in order from least to most efficient.

- Mechanical collectors (cyclone or multiclones)
- Wet scrubber
- Fabric filter baghouse
- Electrostatic precipitator (ESP)

6.1.1 Mechanical Collectors

Wet scrubbers, baghouses and ESPs are the particulate control devices 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. The PWL hogged fuel boiler is already equipped with a multiclone upstream of the existing wet scrubbers. A multiclone is an array of cyclones used to mechanically separate particulate matter emissions from the boiler flue gas. The multiclone removes cinders and entrained fuel particles as well as the much smaller PM_{10} emissions.

This analysis evaluates the cost and feasibility of changing the secondary PM_{10} emissions control equipment downstream of the multiclone to improve the collection efficiency. The multiclone would not be removed or replaced.

6.1.2 Wet Scrubbers

In wet scrubbing processes, liquid or solid particles are removed from a gas stream by transferring them to a liquid. The liquid most commonly used is water. A wet scrubber's particulate collection efficiency is directly related to the amount of energy expended in contacting the gas stream with the scrubber liquid. Most wet scrubbing systems operate with particulate collection efficiencies over 95 percent.[19]

The two wet scrubbers were installed in 1987 to control emissions from boiler PH2. Each scrubber receives approximately 50% of the exit gas flow from the multiclone. They are considered to achieve a 95% control efficiency as stated in 08-0003-TV-01.

PWL has performed emissions testing on the wet scrubber outlets which is used as input data in the four-factor analysis.

6.1.3 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 would 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. It is considered unsafe and therefore infeasible.

6.1.4 Electrostatic Precipitator (ESP)

ESPs are commonly used as a secondary particulate control technology for wood-fired boilers. Dry ESPs are common and do not create a contaminated water stream. They are generally 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 feasibly used in the wood products industry. This is reflected in recently permitted biomass-fired boilers at similar facilities, which were equipped with ESPs to control filterable PM emissions (RBLC IDs SC-0149, ME-0040 and FL-0361).

PM_{10} emissions control via ESP was deemed technically feasible for this analysis. A vendor price quote was received from Wellons. However, the vendor states that the

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[19] EPA: Monitoring by Control Technique - Wet Scrubber For Particulate Matter https://www.epa.gov/air-emissions-monitoring-knowledge-base/monitoring-control-technique-wet-scrubber-particulate-matter

current wet scrubbers can quench significant char being discharged by the furnace. Introduction of char into an ESP will cause fire and potential damage, so furnace tuning, and modifications will be required in that case.

6.1.5 Summary of PM_{10} Control Technologies

The PWL hogged fuel boiler currently must comply with the grain loading limit of 0.10 gr/dscf in accordance with OAR 340-226-0210(2)(b). The analysis has identified an ESP as the only technically feasible, add-on PM_{10} control technology for analysis using the four-factor methodology.

The following four-factor analysis reviews the economic, energy, and environmental impacts of installing an ESP on the boiler. It also reviews the schedule of installation and duration of impact.

6.2 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 source of PM_{10} emissions is the hogged fuel boiler at the PWL facility. Therefore, this analysis will only review control technologies for PM_{10} emissions from PH2 since controlling emissions from the other emissions sources is either technically infeasible, will not be cost effective due to minimal actual emissions, or do not offer substantial benefit as described in Section 4.4.

Current PM_{10} Emissions

Since PH2 is already controlled for PM_{10} via the wet scrubbers, the analysis needs to consider an incremental improvement in emissions from the already controlled rate. Therefore, controlled emissions from the wet scrubbers are used as baseline emissions for the analysis to quantify the additional benefit of alternative control. This creates an "effective" improvement by assessing additional PM_{10} control via an ESP rather than the existing wet scrubbers. The permitted PM_{10} emission rate in Table 10 on page 22 of 08-0003-TV-01 was used to establish the baseline emission rate in the analysis. It represents the current "Emission Factors and Verification Testing" rate of PM_{10} for the hogged-fuel boiler. Therefore, the controlled PM_{10} emission rate from the existing wet scrubbers is 0.198 lb PM_{10} per 1000 lb (klb or Mlb) steam generation. Baseline emissions were calculated using the average boiler steam production rate for reporting years 2016 – 2019. The average boiler steam production rate was 295,671 klb/yr. Baseline PM_{10} emissions emitting from the wet scrubbers are estimated as follows:

$$0.198 \text{ lb/klb} * 295{,}671 \text{ klb/yr} \div 2000 \text{ lb/ton} = 29.3 \text{ tpy}$$

The emission factor of 0.198 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

1.50 MMBtu heat input to 1000 lb steam output (1.50 MMBtu/klb). The current boiler emission factor for PM_{10} emissions from the wet scrubber is equivalent to:

0.198 lb/klb ÷ 1.50 MMBtu/klb = 0.132 lb/MMBtu heat input

The additional potential reduction in PM_{10} emissions are then evaluated when upgrading to an ESP.

Dry-ESP Controlled PM_{10} Emissions

PWL received an estimate from the vendor, Wellons, to install a dry ESP for control of the hogged fuel boiler. The proposal includes achieving a target outlet emissions level of 0.05 lb/MMBtu. This includes a filterable emissions level of 0.045 lb/MMBtu and an estimated 0.005 lb/MMBtu of condensable emissions. The proposed outlet rate was confirmed via a review of BACT determinations for similar wood-fired boilers contained in the EPA RBLC database.

For this analysis, PWL has a final ESP PM_{10} emission rate of 0.05 lb/MMBtu. Therefore, the “additional” control in emissions from the wet scrubbers to an ESP equates to a reduction in emission rates from 0.132 lb/MMbtu to 0.05 lb/MMbtu. This represents the additional PM_{10} removal efficiency when using an ESP for control. The emission factor can be used to calculate ESP-controlled annual emissions as follows:

0.05 lb/MMBtu * 1.50 MMBtu/klb = 0.075 lb/klb
0.075 lb/klb* 295,671 klb/yr = 11.1 tpy

Therefore, the utilization of an ESP results in controlling an additional 18.2 tpy of PM_{10} in comparison to the existing wet scrubbers.

6.3 Factor 1: Cost of Compliance

A cost estimate for installation of an ESP on the hog fuel boiler has been developed based on the cost estimation procedure in Section 6, Chapter 3 of EPA’s Control Cost Manual [8]. A cost estimate is also provided by the ESP vendor (Wellons) with additional cost support provided by KH2A Engineering, Arctic Engineering, and PWL. A spreadsheet with the cost estimation procedure, calculations, and the final calculated cost effectiveness of an ESP is presented in Appendix C. The vendor quote is included in Appendix D.

6.3.1 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 can then be used to estimate ESP cost using the “Full SCA Procedure” [8]. The specific collection area (SCA) and the volumetric flow rate of the exhaust gas are 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 Full SCA Procedure was not necessary for this evaluation because the vendor provided a recommended plate type and size for the ESP, however the EPA Control Cost

Manual was still utilized for the additional cost calculations. The flange-to-flange, field erected cost was used only to determine maintenance costs per EPA Control Cost Manual methodology. However, the flange-to-flange cost is not carried through to the total direct cost. Instead, the equipment costs, direct costs, and indirect installation costs were supplied by Wellons, KH2A, Arctic Engineering, and PWL. Annual cost and capital recovery cost methodology was utilized from the Control Cost Manual. [8]

Total direct cost was established by the Wellons quote of $1,340,000. An additional $400,000 was factored into the total capital investment to account for the removal and decommissioning of the two exiting wet scrubbers. Additional direct and indirect installation and design costs that are beyond the scope of the Wellons quote are included by KH2A, Arctic Engineering, and PWL to accommodate challenges around construction and modification to the existing site. These values were revised to account for specified retrofit difficulty instead of applying the overall retrofit factor. Therefore, a retrofit factor was not applied like the cost analysis for SNCR. Difficulties surrounding the retrofit of the boiler and exiting site layout are further discussed below. The costs and factors are included in the ESP cost evaluation spreadsheet.

The indirect installation costs account for engineering, construction and field expenses, contractor fees, start-up, performance testing, model study, and project contingencies. The provided costs account for the civil engineering, structural engineering, and site work problems that are described in Section 5.4.2 surrounding earthquake design and unsuitable soil conditions. All design and construction considerations for seismic activity and wind loading will be also required for all new or modified construction surrounding the installation of an ESP. Therefore, any work to the existing foundation or any new construction will also require extensive structural design and geotechnical engineering because of the proximity of the Cascadia subduction zone.

Overall, the largest difficulty surrounding the installation of an ESP is available space to accommodate all associated equipment. ***The current configuration at the facility does not have the appropriate space necessary to install an ESP which will require a 12’ x 30’ footprint or larger***. The current area is blocked by the plywood plant to the east, the boiler to the north, pneumatic baghouse to the south, and an egress area to the west which accesses the maintenance shop. So, the installation would require the decommission and removal of the two existing wet scrubbers which would require complete shutdown of the hogged-fuel boiler. A reconfiguration of other equipment in the area would be a potential requirement as well. Figures 6-1 and 6-2 further indicate the lack of space required for an ESP and the necessary removal of the wet scrubbers. Figure 6-1 shows the current layout at PWL and the existing wet scrubbers. Figure 6-2 provides a comparable ESP control unit at SCL. Costs are included in the evaluation to account for the decommissioning and removal of the wet scrubbers as well as site modifications.

Figure 6-1: Current Layout at PWL

Figure 6-2: Comparable ESP at South Coast Lumber for Scale

Accounting for the vendor quote, site preparation, direct, and indirect costs, the TCI calculates to $4,893,200 in 2020 dollars. Again, this does not apply a retrofit factor and instead is accounted for with adjusted costs.

Direct and indirect annual costs were 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. Wage values were provided by PWL. 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%. The discussions surrounding the estimated equipment life and interest rate in regard to the SNCR are also applicable to the ESP. Financing through SCL will likely be at a larger interest rate, however the prime rate is still used in the analysis. A 20-year expected life was also utilized for the ESP because the EPA Control Cost Manual states “20 years being typical” for the control technology.

A critical cost that is not quantified within the cost analysis is the lost revenue due to downtime of the boiler. Boiler downtime would halt LVL, plywood, and veneer operations at PWL. The boiler provides steam to the plywood plant and the plywood plant supplies the other operations with billet. So, boiler downtime effectively shuts down all operations. The cost associated with lost revenue would be critical from a production standpoint as well as the breech in contractual obligations to customers. Even more importantly, the facility would not have operations to provide their 300 employees with work throughout the period.

Total annual direct operations and maintenance (O&M) costs and indirect costs for capital recovery, taxes, insurance, and overhead are calculated at $670,846 per year.

6.3.2 Cost Effectiveness Calculation Results

The tons per year of PM_{10} removed were calculated based on the tons of PM_{10} emitted from the wet scrubbers controlling the boiler to provide an incremental control analysis. The wet scrubbers emit roughly 29.3 tpy of PM_{10}. Modification to an ESP equates to a controlled emission rate of 11.1 tpy based on the same steam production rate. This results in an additional reduction of 18.2 tpy of PM_{10} from the boiler when using an ESP. Cost per ton removed is calculated by dividing the total annual cost by the tons of PM_{10} removed, as shown below:

$670,846/yr ÷ 18.2 tons/yr = $36,893 per ton of PM_{10} removed.

The PM_{10} emissions control cost calculations are summarized in Table 6-1.

Table 6-1: Hogged Fuel Boiler Cost Effectiveness Analysis – PM_{10}

Control Technology	Reduced Emission Rate	Emissions (tons/year)	Emissions Reduction (tons/year)
Existing Multiclone and Wet Scrubbers	Base Case	29.3	Base Case
Fabric Filter Baghouse	Not feasible due to fire danger.		
Electrostatic Precipitator	0.05 lb/MMBtu	11.1	18.2
ESP Cost Parameters			
Boiler Steam Production Capacity	295,671,000 pounds of steam per year		
Estimated ESP Direct and Indirect Capital and Installation Costs	$4.9 million		
Total indirect annual costs, including capital recovery	$580,354		
Total direct annual O&M Costs	$90,492		
Total Annual Capital Recovery and O&M Costs	$670,846		
Cost per ton PM_{10} Removed[20]	$670,846 ÷ 18.2 tpy = $36,893/ton		

6.4 Factor 2: Time Necessary for Compliance

PWL estimates that it would take approximately 24 to 48 months to obtain ESP bids, review, award the contract, then design, permit, finance, install and commission an ESP on the hogged fuel boiler. The cost estimate does not account for lost revenue due to plant downtime required for the decommissioning of the wet scrubbers and construction of the ESP. There is not enough available space at PWL to construct an ESP while operation continues and then connect the boiler to the new control device. Instead, the entire facility would be required to shut down to accommodate the project.

6.5 Factor 3: Energy and Environmental Impacts of Compliance

Installing an ESP on boiler PH2 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.

6.6 Factor 4: Remaining Useful Life

As stated in Section 5.7, the Riley hogged-fuel boiler was installed at PWL in 1986 and was originally commissioned in 1969. The boiler has been adjusted and tuned to efficiently operate with the PWL fuel source of coastal grown logs, recovery wood fiber

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[20] Cost per ton in table 6-1 is based on a 20-year expected equipment life. ESP installation with a 30-year expected life equates to $32,560 per ton PM_{10} removed.

from salvage logs, and sustained yield timber from the Company’s timber lands. Most importantly, the boiler effectively processes residuals from fee timber lands. The remaining useful life of the boiler is considered to be at least the entire duration of the capital recovery period of the cost analysis.

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) requirements. 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 PWL hogged fuel boiler has been located.

Cost effectiveness determinations were also included in the regional haze Round 1 analysis to support 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 PWL wood-fired boiler has determined that adding an ESP to further control PM_{10} emissions would have an effectiveness cost of $36,893/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 PWL wood-fired boiler has determined that adding an SNCR system to control NO_x would have an effectiveness cost of $28,912/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 NOx control.

8.0 CONCLUSION

A four-factor analysis has been conducted for PWL's wood-fired boiler at the Brookings, Oregon plywood facility. The analysis was conducted to meet the requirements of Round 2 of the Regional Haze program to assist ODEQ with the development of a SIP. 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 PWL to perform this four-factor analysis.

The four factors analyzed were based on ODEQ guidance and the RHR to determine if there are emission control options at the Brookings 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.

PWL considered all the emissions sources on the facility and found that the hogged fuel boiler provided the majority of the facility's PM_{10}, NO_x and SO_2 emissions. Therefore, the four-factor analysis was conducted for NO_x and PM_{10} on boiler PH2. SNCR installed on the boiler would have a cost effectiveness of $28,912 per ton of NO_x removed (in 2019 dollars). An ESP installed on the boiler would have a cost effectiveness of $36,893 per ton of PM_{10} removed (in 2019 dollars). 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 due to challenges surrounding space limitations as well as earthquake and soil stability design/construction.

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 PWL. 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 Kalmiopsis Wilderness, are wildfire, woodstove, and miscellaneous 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. Additionally, impairment from anthropogenic sources in the Kalmiopsis Wilderness are dominated by ammonium sulfate. PWL emits very little SO_2 emissions which act as a precursor pollutant to ammonium sulfate. Conversely, ammonium nitrate has very little contribution to impairment in the Kalmiopsis Wilderness. Therefore, a reduction of NO_2 emissions at PWL will provide little impact towards the improvement of visibility in the wilderness. Prior to imposition of controls on industry, ODEQ needs to ensure that those requirements will have a discernable and causal impact on the improvement of visibility in the Class I areas. Enforced reductions to industrial emissions that are minimal or non-contributing factors to regional haze in a Class I area will neither improve visibility nor contribute to the reasonable progress goals of the Regional Haze program.

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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

Pacific Wood Laminates, Inc.
PO Box 820
Brookings, OR 97415-0200

Re: Regional Haze Four Factor Analysis; Pacific Wood Laminates, Inc.

Dear Pacific Wood Laminates, Inc.:

The purpose of this letter is to inform you that the Oregon Department of Environmental Quality (DEQ) has identified the Pacific Wood Laminates, Inc. 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]

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[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:	08-0003
Federal Facility ID:	8416611
Facility name:	Pacific Wood Laminates, Inc.
Facility Address	815 N RAILROAD AVE
Facility City, State, Zip	BROOKINGS, OR 97415

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
52.5	3.27	139.1	194.9	76	29	189	294

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

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[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.

submissions incomplete if submitted without supporting information. The analysis should be 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.

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[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

APPENDIX B: 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

Step 1: Please select on the ***Data Inputs*** tab and click on the ***Reset Form*** button. This will reset the NSR, plant elevation, estimated equipment life, desired dollar year, cost index (to match desired dollar year), annual interest rate, unit costs for fuel, electricity, reagent, water and ash disposal, and the cost factors for maintenance cost and administrative charges. All other data entry fields will be blank.

Step 2: Select the type of combustion unit (utility or industrial) using the pull down menu. Indicate whether the SNCR is for new construction or retrofit of an existing boiler. If the SNCR will be installed on an existing boiler, enter a retrofit factor equal to or greater than 0.84. Use 1 for retrofits with an average level of difficulty. For more difficult retrofits, you may use a retrofit factor greater than 1; however, you must document why the value used is appropriate.

Step 3: Select the type of fuel burned (coal, fuel oil, and natural gas) using the pull down menu. If you selected coal, select the type of coal burned from the drop down menu. The NOx emissions rate, weight percent coal ash and NPHR will be pre-populated with default factors based on the type of coal selected. However, we encourage you to enter your own values for these parameters, if they are known, since the actual fuel parameters may vary from the default values provided.

Step 4: Complete all of the cells highlighted in yellow. As noted in step 1 above, some of the highlighted cells are pre-populated with default values based on 2014 data. Users should document the source of all values entered in accordance with what is recommended in the Control Cost Manual, and the use of actual values other than the default values in this spreadsheet, if appropriately documented, is acceptable. You may also adjust the maintenance and administrative charges cost factors (cells highlighted in blue) from their default values of 0.015 and 0.03, respectively. The default values for these two factors were developed for the CAMD Integrated Planning Model (IPM). If you elect to adjust these factors, you must document why the alternative values used are appropriate.

Step 5: Once all of the data fields are complete, select the ***SNCR Design Parameters*** tab to see the calculated design parameters and the ***Cost Estimate*** tab to view the calculated cost data for the installation and operation of the SNCR.

Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? 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

Factor not adjusted. Retrofit difficulty instead accounted for in additional Capital Costs evaluated by KH2A Engineering, Arctic Engineering, and PWL.

Complete all of the highlighted data fields:

			Note
What is the maximum heat input rate (QB)?	86	MMBtu/hour	a
What is the higher heating value (HHV) of the fuel?	17,480,000	Btu/BDT	b
What is the estimated actual annual fuel consumption?	27,883	BDT/Year	c
Is the boiler a fluid-bed boiler?	No		
Enter the net plant heat input rate (NPHR)	17.5	MMBtu/MW	d

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	1 BDT/MW	d

Provide the following information for coal-fired boilers: **NOT APPLICABLE**

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

Enter the following design parameters for the proposed SNCR:

			Note
Number of days the SNCR operates (t_{SNCR})	336	days	e
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.2458	lb/MMBtu	f
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.1450	lb/MMBtu	g
Estimated Normalized Stoichiometric Ratio (NSR)	1.99	Must be <2.0, above that no eff. increase and ammonia slip	h

Plant Elevation	102	Feet above sea level

59.89

35.33

*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
Select the reagent used	Urea ▼	

Densities of typical SNCR reagents:

50% urea solution	71	lbs/ft^3
29.4% aqueous NH_3	56	lbs/ft^3

Enter the cost data for the proposed SNCR:

					Note
Desired dollar-year	2019				
CEPCI for 2019	607.5	CEPCI Annual Avg. for 2019	541.7	2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	3.25	Percent	***Current Prime Rate - See note h***		i
Fuel ($Cost_{fuel}$)	2.00	\$/MMBtu			j
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			

* 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)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0676	U.S. Energy Information Administration. Electric Power Monthly. Table 5.3. Published December 2017. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.	
Fuel Cost ($/MMBtu)	-	Select fuel type	
Ash Disposal Cost ($/ton)	-	Select fuel type	
Percent sulfur content for Coal (% weight)	-	Select fuel type	
Percent ash content for Coal (% weight)	-	Select fuel type	
Higher Heating Value (HHV) (Btu/lb)	-	Select fuel type	
Interest Rate (%)	5.5	Default bank prime rate	

User Input Notes

a The rated capacity of the boiler is 86 MMBtu/hr per 08-0003-TV-01.

b HHV of hog fuel is 17.48 MMBtu/ton per GHG Baseline Emissions in 08-0003-TV-01.

c Four year average (2017 - 2019) of actual annual fuel production (BDT/year). See PWL Reference Values tab.

d NPHR value adjusted for Biomass fuel. http://www.ucanr.org/sites/WoodyBiomass/newsletters/InfoGuides43283.pdf
8000 - 10,000 BDT/year = 1 MW; over 8760 hours per year equates to approx. 1 BDT/MW
(17,480,000 btu/BDT) x (MMBtu/10^6 btu) x (1 BDT/MW) = 17.48 MMBtu/MW

e PH2 boiler maximum operating schedule is 8,064 hours per year per Current Plant Site Operating Limits (24.b.) in 08-0003-TV-01.

f Inlet NOx ratio based on source test data from June 11, 2019. Inlet NOx (lb/MMBtu) represented by average rate from test.

g Outlet NOx emissions based on requirement to keep Normalized Stoichiometric Ratio (NSR) below 2.0 to avoid ammoinia slip. Results in ~41% control efficiency.

h NSR calculated using Equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost manual.

$$NSR = \frac{[2\,NO_{x_{in}} + 0.7]\eta_{NO_x}}{NO_{x_{in}}}$$

i Current prime rate of 3.25%. The rate one year ago was at 5.5% which is considered default value in OAQPS spreadsheet.

j Fuel Cost is based on $35/BDT, delivered, and 17.5 MMBtu/BDT.

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 =	86	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	(QB x 1.0E6 Btu/MMBtu x 8760)/HHV =	43,098	BDT/Year
Actual Annual fuel consumption (Mactual) =		27,883	BDT/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.75	
Total System Capacity Factor (CF_{total}) =	(Mactual/Mfuel) x (tSNCR/365) =	0.60	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	5217	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	41	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	8.67	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	22.60	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)		
SO_2 Emission rate =	(%S/100)x(64/32)*($1x10^6$)/HHV =		
Elevation Factor (ELEVF) =	14.7 psia/P =		
Atmospheric pressure at 102 feet above sea level (P) =	$2116x[(59-(0.00356xh)+459.7)/518.6]^{5.256}$ x (1/144)* =	14.7	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.00	

NOTE: Limited to 41% to prevent ammonia slip as dictated by NSR

Not applicable; factor applies only to coal-fired boilers

Not applicable; factor applies only to coal-fired boilers

Not applicable; elevation factor does not apply to plants located at elevations below 500 feet.

* 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)	27	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol}$ =	55	lb/hour
	(m_{sol} x 7.4805)/Reagent Density =	5.8	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24 hours/day)/Reagent Density =	2,000	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i $(1+ i)^n/(1+ i)^n$ - 1 = Where n = Equipment Life and i= Interest Rate	0.0688

Parameter	Equation	Calculated Value	Units	
Electricity Usage: Electricity Consumption (P) =	(0.47 x NOx_{in} x NSR x Q_B)/NPHR =	1.1	kW/hour	
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	26	gallons/hour	
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.22	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 ($SNCR_{cost}$) =	\$800,000 in 2019 dollars	*Wellons Quote*
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2019 dollars	*Spreadsheet Calculated*
Balance of Plant Costs (BOP_{cost}) =	\$523,656 in 2019 dollars	
Civil and Structural Engineering	\$600,000 in 2019 dollars	*KH2A, Arctic, and PWL Provided*
Building Costs, Site-Work, Concrete, Fire System	\$1,800,000 in 2019 dollars	
Boiler Modification (ID Fan, F.D. Fan)	\$3,150,000 in 2019 dollars	
CEMs System	\$250,000 in 2019 dollars	
Total Capital Investment (TCI) =	\$7,123,656 in 2019 dollars	*Total*

* 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 ($SNCR_{cost}$) =	\$800,000 in 2019 dollars	**Vendor Quote (Wellons)**

Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs (BOP_{cost}) =	$523,656 in 2019 dollars	**Spreadsheet Calculated**

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$160,182 in 2019 dollars
Indirect Annual Costs (IDAC) =	$493,313 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	$653,495 in 2019 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash

Annual Maintenance Cost =	0.015 x TCI =	$106,855 in 2019 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$50,039 in 2019 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$398 in 2019 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$572 in 2019 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$2,317 in 2019 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$0 in 2019 dollars
Direct Annual Cost =		$160,182 in 2019 dollars

Indirect Annual Cost (IDAC)

IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	$3,206 in 2019 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$490,108 in 2019 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$493,313 in 2019 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$653,495 per year in 2019 dollars
NOx Removed =	22.6 tons/year
Cost Effectiveness =	**$28,912 per ton of NOx removed in 2019 dollars**

Pacific Wood Laminates
PH2 Boiler Data

<u>Fuel Consumption and Steam Production</u>

Total Flow Per Year

Year	Steam Flow (lbs)	Fuel Input (BDT)	Fuel Efficiency (lbs Steam/BDT)
2019	281,997,260	24,924	11,314
2018	292,847,339	26,832	10,914
2017	303,542,239	31,200	9,729
2016	304,296,216	28,574	10,649
2016 - 2019 Avg.	*295,670,764*	*27,883*	*10,652*

Boiler operations continue to be refined and adjusted to accomplish higher operational efficiency.

<u>Source Test Results - Inlet NOx Value</u>
<u>PH2 Boiler Controlled by Wet Scrubber 1 and 2</u>

Compliance Source Test - June 11, 2019

APPENDIX C: ELECTROSTATIC PRECIPITATOR COST ANALYSIS CALCULATIONS

Pacific Wood Laminates (PWL) PH2 Hogged Fuel Boiler
Regional Haze Four-Factor Analysis

PM Control ***Replace Wet Scrubber(s) with Electrostatic Precipitator (ESP)***
The multiclone will remain upstream of the ESP

Key

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

Design Basis - PH2 Hogged Fuel Boiler			**Source**
Pollutant source	Wood-fired Boiler (Hogged Fuel and Sanderdust)		
Flow, max	53,903	ACFM	1
Temperature	490	deg. F	2
Basis of ton/yr calculations, boiler steam production	295,671	klb/yr	3

Year	Steam (klb)
2019	281,997
2018	292,847
2017	303,542
2016	304,296
Average	295,671

Hours of Operation of ESP for Calculations	8,064	hr/yr	4
Boiler Efficiency, MMBtu/Mlb Steam.	1.50	MMBtu/klb	5
Assumed equipment life	20	years	6
Data Used to Determine Tons of Emissions Controlled			
Steam Flow Rate Used for Calculations (referenced above)	295,671	klb/yr	
Current controlled PM10 emission factor (**Exiting wet scrubbers**)	0.198	lb/klb	7
ESP-controlled PM10 emission rate (**From Wellons**)	0.050	lb/MMBtu	8
ESP-controlled emission rate, converted units	0.075	lb/klb	
Current PM10 Wet Scrubber-Controlled Emissions (testing requirement)	29.3	ton/yr	
PM10 ESP-Controlled Emissions	11.1	ton/yr	
Additional PM10 removed (Wet scrubber to ESP)	18.2	ton/yr	

ESP Equipment for Control Cost Manual Calculations

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

From Figure 3.5: Plate area: 12,320 ft^2 **Wellons Proposal**

Flange-to-flange, field-erected, with standard options: $ 328,998 1987 dollars

Based on Wellons Plate Area

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 April 2020: 206.6 9

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

Adjusted cost: $ 628,032 2020 dollars

COST ESTIMATE

Cost Item	Factor			Source
Total Capital Investment, TCI				
ESP + auxiliary equipment				
Flange-to-flange, field-erected, standard options, 2020 $		$ 628,032		
ESP + auxiliary equipment	A	$ 628,032		
(Used to calculate maintenance cost. Not included in total direct cost below. Already accounted for in Wellons quote.)				
Direct Costs				
Site preparation (Removal of Wet Scrubbers)		$ 400,000		12
Wellons Quote		$ 1,340,000		12
Direct installation costs (outside of Wellons quote)				
Foundation and supports (Additional earthquake design)		$ 950,000		12
Handling and erection		$ 320,000		12
Electrical (Boiler and adjacent infrastructure)		$ 200,000		12
Piping (New Duct Work to Unit, From I.D. Fan)		$ 50,000		12
Insulation for ductwork		$ 14,000		12
Painting		$ 14,000		12
Direct installation costs (subtotal)		$ 1,548,000		
Total Direct Costs, DC	**SP + Wellons Quote + Direct Installation**	**$ 3,288,000**		
Indirect Costs (Installation). Based on Contractor Input				
Engineering		$ 350,000		12
Cascadia earthquake design and certification				
Site design and re-arrangement due to space constraints				
Construction and field expenses		$ 750,000		12
Cascadia earthquake design and certification				
Site design and re-arrangement due to space constraints				
Contractor fees		$ 400,000		12
Project installation work				
Demolition of Old IWS Duct Work and Scrubber Tank				
Start-up		$ 15,000		12
Performance test		$ 15,000		12
Model study		$ 35,000		12
Contingencies	0.03*Wellons Quote	$ 40,200		12
Total Indirect Costs, IC		**$ 1,605,200**		
Total Capital Investment, TCI = DC + IC				
No retrofit factor applied.		**$ 4,893,200**	**2020 dollars**	
Instead applied specific costs.				

Total Annual Costs, TAC								
Direct Annual Cost								
Operating labor, coordination					$	11,798		
Basis:	Annual mean wage	$	58,990					10
	Fraction of ESP time		0.2					11
	Fraction of ESP time * annual labor cost							
Operating labor, per shift					$	31,579		6
Basis:	Mean hourly wage	$	21.93	/hr				12
	Labor per shift		1	hr/shift				12
	Number of shifts		4	shift/day				12
	Operating days		360	day/year				12
Total operating labor					$	43,377		
Supervisory labor			0.15 L		$	6,507		6
				Total Annual Labor	**$**	**49,884**		
Maintenance labor					$	23,793		6
Basis:	Maintenance labor estimated at:							
			15	h/wk				6
			44	wk/yr				6
	Same wage as above	$	36.05	/hr				13
Maintenance materials			0.01	* Equip cost	$	6,280		6
Basis:	Equip cost = A above	$	628,032					
				Total Annual Maintenance	**$**	**30,073**		6
Electricity (ESP)					$	7,812	Annual Avg Load	6
Basis:	Full load power use		14	kW				13
	Electricity ($\text{Cost}_{\text{elect}}$)		0.0692	$/kWh				14
Electricity (ID Fan)					$	2,722		6
Basis:	fan kWh/yr = 0.000181*ACFM*delta P*hr/yr							
	ACFM from above:		53,903	ACFM				12
	delta P, estimate:		0.5	in. H2O				11
			8,064	hr/yr				4
	additional fan kWh/yr =		39,338	kWh/yr				6
	Annual cost = fan kWh/yr * $/kWh (above)							
Do not include costs for compressed air and dust disposal.								
Direct Annual Costs Summary								
Total Annual Labor					$	49,884		
Total Annual Maintenance					$	30,073		
Electricity (ESP)					$	7,812		
Electricity (ID Fan)					$	2,722		
				Total Direct Annual Costs	**$**	**90,492**		

Indirect Annual Costs								
Capital recovery costs					$	336,652		6
Basis:	Capital Recovery Factor (CRF) * TCI							
	CRF = $i\ (1+i)^n/((1+i)^n - 1) =$			0.0688				6
	Where n = Equipment Life and i= Interest Rate							
	Annual Interest Rate (i), percent			3.25				15
Administrative charges (includes taxes, insurance)					$	195,728		6
Basis:	0.04 * TCI							
Overhead					$	47,974		6
Basis:	60% * (operating + supervisory + coordination							
	+ maintenance labor + maintenance materials)							
From above:								
labor	operating	$	31,579					
	supervisory	$	6,507					
	coordination	$	11,798					
	maintenance	$	23,793					
materials	maintenance	$	6,280					
		$	79,957					
Indirect Annual Costs Summary								
Capital recovery costs					$	336,652		
Administrative charges (includes taxes, insurance)					$	195,728		
Overhead					$	47,974		
				Total Indirect Annual Costs	**$**	**580,354**		
Total Annual Costs Summary								
				Total Direct Annual Costs	$	90,492		
				Total Indirect Annual Costs	$	580,354		
				Total Annual Cost	**$**	**670,846**		
				Tons per year PM10 removed		18.2		
				Cost Effectiveness	**$**	**36,893**	**/ton PM_{10} removed**	

*Sources:

1 Permit 08-0003, Review Report P. 7 of 43. Multiclone inlet Q, assume equals outlet Q.

2 Permit 08-0003, Review Report P. 7 of 43. Boiler outlet T, assume no ΔT in the multiclone.

3 Average boiler steam production (2016 - 2019). Representative actual production.

4 PH2 boiler maximum operating schedule is 8,064 hours per year per Current Plant Site Operating Limits (24.b.) in 08-0003-TV-01.

5 Boiler Efficiency conversion is 1500 Btu/lb steam (p. 90 of 94)

6 EPA Cost Control Manual, Section 6 Particulate Matter Controls, Chapter 3 Electrostatic Precipitators. September 1999. (20 years considered typical). See four-factor analysis report for more discussion.

7 Permit PM10 emission rate "Emission Factors and Verification Testing" reporting value, Table 10, page 22 of 94.

8 ESP guaranteed controlled emission rate, provided by Wellons.

9 PPI Apr 2020 - https://beta.bls.gov/dataViewer/view/timeseries/PCU33341333341311

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 51-1011, Supervisors of Production and Operating Workers

11 Estimate

12 Provided by PWL, KH2A, and/or Arctic Engineering

13 Based on ESP Vendor information

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 June 8, 2020: https://www.federalreserve.gov/releases/h15/

APPENDIX D: WELLONS COST QUOTE

From: Brian Murphy
To: Brian Murphy
Subject: Rough budget estimates request
Date: Thursday, June 11, 2020 4:19:27 PM

---------- Forwarded message ---------
From: **Ken Kinsley** <Ken.Kinsley@wellons.com>
Date: Fri, Apr 3, 2020 at 8:33 AM
Subject: rough budget estimates request
To: James De Hoog <polarbear.jd20@gmail.com>
Cc: nolanr@socomi.com <nolanr@socomi.com>, Andrew Israelson <Andrew.Israelson@wellons.com>, bob.vanwassen@gmail.com <bob.vanwassen@gmail.com>

James;

Wellons has been asked to provide some rough budget estimates for certain emissions control system possibilities for Pacific Wood Laminates existing, Riley, 50,000PPH capacity wood-fired boiler in Brookings.

SELECTIVE NON-CATALYTIC REDUCTION (urea injection) FOR NOX REDUCTION.
This technology injects a urea solution into an appropriate temperature zone of the boiler furnace for a chemical reaction that converts NOx to NO2 and water. Successful applications of this technology generally see a 50% reduction in NOx.
However, to be successful, the appropriate temperature zone must be identified and the furnace configuration analyzed to determine where the urea injection should occur, and to determine if there is enough residence time for the chemical reaction.
Additionally, the range of operating load must be evaluated. Injection optimized for full load operation may not be successful at partial loads.
Detailed engineering modeling of the boiler would be required to determine how to implement the addition of an SNCR systemj.

The following is a general description;

A urea-based selective non-catalytic reduction (SNCR) system to lower the NOx emissions in the flue gas from the boiler system. The SNCR system is designed to lower the uncontrolled NOx emissions in the stack flue gas by approximately 50%. The SNCR system injects an atomized urea solution (CO[NH2]2 + water) into the boiler combustion chamber. The urea injection will be controlled based on a signal from the flue gas NOx monitor in the exhaust stack (part of the Owner's CEMS system). The amount of urea required will depend on the amount of NOx to be removed from the flue gas.

Based upon an up-front engineering study, the injection locations inside the combustion chamber would be selected to have the proper flue gas temperatures, have good mixing of the urea with the flue gas, and have the proper residence time to convert the NOx and urea into nitrogen and water vapor.

Items to be determined during the engineering study:

-does the furnace configuration provide an adequate temperature window and residence time?

-will system adjustments for adequate urea injection result in increased CO emissions?
-how stable is the boiler operation, what is the required operating range?
-how would injection nozzles penetrate the furnace walls?
-is there adequate treated water and compressed air supplies?
-locations for tank, and system hardware?
-is there an "ammonia slip" limitation?

NOTE: in some applications the urea injection process creates additional non-condensable artifact compounds that increase the total system particulate level.

BUDGETARY INSTALLED COST ESTIMATE:.............................$800,000.00.
This estimate includes the urea storage tank, system piping, compressed air system, mixing, atomizing and injection skid, distribution manifolds and hoses, injection nozzles, control panels, controls logic and software, mechanical installation and field wiring, but does not include costs to modify the boiler, site work to accommodate the added equipment, equipment weather enclosures, upgrades to the existing boiler control system, or emissions monitoring and data acquisition equipment (CEMS) as needed to provide a stack NOx level signal to the injection controls.

DRY ELECTROSTATIC PRECIPITATOR (ESP) FOR FILTERABLE PARTICULATE REDUCTION
A multiple field, dry ESP could be added to the boiler system exhaust, although this would require the decommissioning of the existing wet scrubbers. Because these scrubbers also help remove HCl and VOCs it would be expected that these levels would increase.
Based upon available boiler information, and a target outlet emissions level of 0.05#/MMBtu (filterable particulate emissions level of 0.045#/MMBtu and an estimated 0.005 condensable outlet), a Wellons Size 6 ESP with an approximate collecting area of 12,320 square feet has been estimated. It has been assumed that the existing boiler system has an effective multiple cyclone collector for char removal upstream of the ESP.
Unfortunately, we cannot offer an effective ESP that has an overall height under 40 feet. This size #6 has a roof height of 45ft above grade, with rapper hardware on the roof extending another 7 feet. The ESP would discharge into a 4ft diameter grade mounted stack with a discharge height of 50 ft.
NOTE: the current installation of wet scrubbers can conceal the fact that significant char is being discharged by the furnace but quenched at the scrubbers. Introduction of char into the ESP will cause fires and potential ESP damage. Furnace tuning and control/operating modifications may be required if this is the case.

BUDGETARY INSTALLED COST ESTIMATE...$1,340,000.

Includes equipment, engineering & design, control system & software, continuous opacity monitor, standard foundations, mechanical installation & electrical wiring, start up support. You would need to add an allowance for ductwork from the existing boiler system to the ESP inlet (will depend on where the ESP is located). Electrical power, final ash handling & disposal provisions

Let us know if anything else is needed, or any questions.

Ken Kinsley
Wellons, Inc.
360-750-3505

Swanson Group **A**ccountability **C**ommitment **E**xcellence **S**afety

Swanson Group Manufacturing
PO Box 250
Glendale, OR 97442
Office (541) 832-1121
Fax (541) 832-1139
www.swansongroup.biz

June 1, 2020

DEPT OF ENVIRONMENTAL QUALITY
RECEIVED
JUN 03 2020
NORTHWEST REGION

Department of Environmental Quality
Agency Headquarters
700 NE Multnomah Street, Suite 600
Portland, OR 97232

Subject: Regional Haze Four Factor Analysis; Swanson Group Mfg.LLC

Per your request Swanson Group has completed the analysis for our plywood production facility in Glendale Oregon.

DEQ Facility ID:	10-0045
Federal Facility ID:	8004811
Facility name:	Swanson Group Mfg. LLC
Facility Address:	303 MEHLWOOD LANE Glendale, OR 97442

Sincerely

Jeff Remington

Jeff Remington
VP of Engineering
Office 541-832-1194
Cell 541-761-0533
E-fax 541-832-1433

REGIONAL HAZE
FOUR FACTOR ANALYSIS

SWANSON GROUP MANUFACTURING

Prepared for
SWANSON GROUP MFG. LLC
GLENDALE, OREGON
May 29, 2020
Project No. 0472.04.01

Prepared by
Maul Foster & Alongi, Inc.
6 Centerpointe Drive, Suite 360, Lake Oswego, OR 97035

MAUL
FOSTER
ALONGI

CONTENTS

LIMITATIONS

TABLES

ACRONYMS AND ABBREVIATIONS

$/ton	dollars per ton of pollutant controlled
°F	degrees Fahrenheit
Analysis	Regional Haze Four Factor Analysis
CAA	Clean Air Act
CFR	Code of Federal Regulations
Control Cost Manual	USEPA Air Pollution Control Cost Manual
DEQ	Oregon Department of Environmental Quality
ESP	electrostatic precipitator
existing permit	Title V Operating Permit no. 10-0045-TV-01
facility	veneer and plywood manufacturing facility located at 303 Mehlwood Lane, Glendale, Oregon 97442
Federal Guidance Document	Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003
GACT	Generally Available Control Technology
HAP	hazardous air pollutant
hogged fuel boiler	Babcock and Wilcox Dutch-oven-type hogged fuel boiler
MFA	Maul Foster & Alongi, Inc.
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO	nitric oxide
NO_X	oxides of nitrogen
PCWP	Plywood and Composite Wood Products
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns or less
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
Swanson	Swanson Group Mfg. LLC
USEPA	U.S. Environmental Protection Agency
VOC	volatile organic compound

1 INTRODUCTION

The Oregon Department of Environmental Quality (DEQ) is developing a State Implementation Plan (SIP) as part of the Regional Haze program in order to protect visibility in Class I areas. The SIP developed by the DEQ covers the second implementation period ending in 2028, and must be submitted to the U.S. Environmental Protection Agency (USEPA) for approval. The second implementation period focuses on making reasonable progress toward national visibility goals, and assesses progress made since the 2000 through 2004 baseline period.

In a letter dated December 23, 2019, the DEQ requested that 31 industrial facilities conduct a Regional Haze Four Factor Analysis (Analysis). The Analysis estimates the cost associated with reducing visibility-impairing pollutants including, particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), oxides of nitrogen (NO_X), and sulfur dioxide (SO_2). The four factors that must be considered when assessing the states' reasonable progress, which are codified in Section 169A(g)(1) of the Clean Air Act (CAA), are:

(1) The cost of control,

(2) The time required to achieve control,

(3) The energy and non-air-quality environmental impacts of control, and

(4) The remaining useful life of the existing source of emissions.

The DEQ has provided the following three guidance documents for facilities to reference when developing their Analysis:

(1) USEPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003 (Federal Guidance Document).

(2) USEPA Air Pollution Control Cost Manual, which is maintained online and includes separate chapters for different control devices as well as several electronic calculation spreadsheets that can be used to estimate the cost of control for several control devices (Control Cost Manual).

(3) Modeling Guidance for Demonstrating Air Quality Goals for Ozone, [particulate matter with an aerodynamic diameter of 2.5 microns or less] $PM_{2.5}$, and Regional Haze (November 2018), EPA-454/R-18-009.

The development of this Analysis has relied on these guidance documents.

1.1 Facility Description

Swanson Group Mfg. LLC (Swanson) owns and operates a veneer and plywood manufacturing facility located at 303 Mehlwood Lane, Glendale, Oregon 97442 (the facility). Swanson was among the 31 industrial facilities requested by the DEQ to conduct an Analysis. The facility currently operates under

Title V Operating Permit no. 10-0045-TV-01 (existing permit) issued by the DEQ on June 12, 2017. The facility is a major stationary source of criteria pollutants only.

The facility is located due north of Glendale city center and is situated in a small valley that is surrounded by significant topographical features in each cardinal direction. It is important to note that the nearest federal Class I area is the Kalmiopsis Wilderness Area, approximately 48.8 kilometers southwest of the facility.

1.2 Process Description

Raw green logs from off-site sources are delivered to the facility by trucks and are stored in the log yard. Received logs are cut to length prior to conditioning in log vats. After conditioning, the logs are peeled to produce thin layers of green veneer, which are then sold or sent for drying. There are three veneer dryers at the facility.

After drying is complete, a portion of the dried sheets is sent to the patch process for finishing. In the patch process, adhesives are applied to sorted sheets to produce plywood sheets. Plywood sheets are then sent to one of three presses for curing. Once curing is complete, rough-cut plywood is further finished by repairing board imperfections, sanding, and cutting to final product dimensions. Heat used by each press, the log vats, and each veneer dryer is generated by the Babcock and Wilcox Dutch-oven-type hogged fuel boiler (hogged fuel boiler).

2 APPLICABLE EMISSION UNITS

Swanson retained Maul Foster & Alongi, Inc. (MFA) to assist the facility with completing this Analysis. Emissions rates for each visibility-impairing pollutant (PM_{10}, NO_X, and SO_2) were tabulated. These emissions rates represent a reasonable projection of actual source operation in the year 2028. As stated in the Federal Guidance Document,[1] estimates of 2028 emission rates should be used for the Analysis. It is assumed that current potential to emit emission rates at the facility represent the most reasonable estimate of actual emissions in 2028.

After emission rates were tabulated for each emissions unit, estimated emission rates for each pollutant were sorted from the highest emission rate to the lowest. The emission units collectively contributing up to 90 percent of the total facility emissions rate for a single pollutant were identified and selected for the Analysis.

This method of emission unit selection ensures that larger emission units are included in the Analysis. Larger emission units represent the likeliest potential for reduction in emissions that would contribute to a meaningful improvement in visibility at federal Class I areas. It would not be reasonable to assess many small emission units—neither on an individual basis (large reductions for a small source likely would not improve visibility and would not be cost effective), nor on a collective basis (the aggregate

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[1] See Federal Guidance Document page 17, under the heading "Use of actual emissions versus allowable emissions."

emission rate would be no greater than 10 percent of the overall facility emissions rate, and thus not as likely to improve visibility at federal Class I areas, based solely on the relatively small potential overall emission decreases from the facility).

The following sections present the source selection, associated emission rates that will be used in the Analysis, and pertinent source configuration and exhaust parameters.

2.1 Sources of PM_{10} Emissions

A summary of the selected emission units and associated PM_{10} emission rates included in the Analysis is presented in Table 2-1 (attached). A detailed description of each emissions unit is presented below. The permit emission unit ID is shown in parentheses.

2.1.1 Hogged Fuel Boiler (1PH)

Hogged fuel for use in the hogged fuel boiler is supplied primarily by off-site sources. However, residual bark, sanderdust, and plytrim generated on site are used when readily available. The hogged fuel boiler has a maximum rated heat input capacity of 125 million British thermal units per hour. Its rated design capacity is 75,000 pounds of steam per hour, which is used to provide heat for various types of equipment at the facility. Exhaust generated by operating the hogged fuel boiler is routed to a multiclone for control of coarse particulate emissions, then to a dry electrostatic precipitator (ESP) for control of fine particulate emissions. The hogged fuel boiler can also utilize process exhaust generated by operation of the three veneer dryers as a supplemental fuel source.

The hogged fuel boiler is subject to, and is required to comply with, Area Source Boiler Generally Available Control Technology (GACT) regulations, which are codified at Title 40 Code of Federal Regulations (CFR) 63 Subpart JJJJJJ, as introduced under Section 112(g) of the CAA. Based on USEPA guidance[2] provided to states for the Second Implementation Period, the USEPA believes that it is reasonable for states to exclude an emission source for further analysis if:

> For the purpose of [particulate matter (PM)] control measures, a unit that is subject to and complying with any CAA section 112 National Emission Standard for Hazardous Air Pollutants (NESHAP) or CAA section 129 solid waste combustion rule, promulgated or reviewed since July 31, 2013, that uses total or filterable PM as a surrogate for metals or has specific emission limits for metals. The NESHAPs are reviewed every 8 years and their emission limits for PM and metals reflects at least the maximum achievable control technology for major sources and the generally available control technology for area sources. It is unlikely that an analysis of control measures for a source meeting one of these NESHAPs would conclude that even more stringent control of PM is necessary to make reasonable progress.

Based on the USEPA guidance, the hogged fuel boiler was excluded from further evaluation in the Analysis. It is also important to note that the hogged fuel boiler is already well controlled for fine particulate emissions by the state-of-the-art dry ESP.

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[2] USEPA Office of Air Quality Planning and Standards. "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period." August 2019.

2.1.2 Veneer Dryer Fugitives (5VDa)

The veneer dryer fugitives emissions unit represents leaking emissions from seals, gaskets, and miscellaneous openings on the veneer dryers at the facility. Emissions from leaks are generated as fresh, green veneer is dried in each veneer dryer. The facility has a total of three veneer dryers (grouped in the existing permit as emission unit 5VD). Additional details describing the operation and size of each veneer dryer are presented in Section 2.1.2.1 for clarity.

Only PM_{10} emissions associated with the veneer dryer fugitives emissions unit (i.e., excluding emissions unit 5VD, point source veneer dryer emissions) meets the threshold of 90 percent contribution to the total facility PM_{10} emissions rate. However, each veneer dryer was recently rebuilt (within the last five years) in order to minimize the potential for fugitive emissions. There is also no reasonable way to capture fugitive emissions from veneer dryer leaks and route them to a downstream control device. Therefore, because of the recent reconstruction and the feasibility issues related to capturing and routing emissions, the veneer dryer fugitives emissions unit was excluded from further evaluation in the Analysis.

2.1.2.1 Veneer Dryers (5VD)

As stated above, there are three veneer dryers at the facility, which are used to dry green, freshly cut veneers to optimal moisture content depending on product specifications. Each veneer dryer at the facility is indirectly heated by steam generated by the hogged fuel boiler.

Veneer dryer no. 1 is a six-deck, two-zone Moore longitudinal dryer with a maximum drying capacity of 12,000 square feet per hour on a three-eighths-inch basis. Veneer dryer nos. 2 and 3 are four-deck, four-zone Moore jet dryers, each with a maximum drying capacity of 9,000 square feet per hour on a three-eighths-inch basis.

Process exhaust from the veneer dryers can be routed one of two ways, depending on the operating scenario. During operating scenario no. 1, process exhaust from the heated zones of each veneer dryer is routed through a heating coil, followed by a regenerative thermal oxidizer for control of volatile organic compound (VOC) and hazardous air pollutant (HAP) emissions. During operating scenario no. 2, process exhaust from the heated zones of each veneer dryer is routed to the hogged fuel boiler combustion zone for control of VOC and HAP emissions.

It is important to note that the veneer dryer emissions unit did not meet the threshold of 90 percent contribution to the total facility PM_{10} emissions rate. Therefore, the veneer dryers were not included in the Analysis and are presented here only for reference.

2.1.3 Plywood Press Nos. 1 through 3 (P1, P2, and P3)

There are three plywood presses at the facility, each hydraulically driven and heated, typically up to 300 degrees Fahrenheit (°F) above ambient temperature, via steam produced by the hogged fuel boiler. Uncontrolled plywood press emissions are produced during pressing and as the press is released, and are emitted to atmosphere via nearby roof vents.

Press no. 1 is a Columbia batch press with a rated capacity of 7.5 batches per hour, which is equivalent to 270 sheets per hour. Press no. 2, also a Columbia batch press, has a rated capacity of 7.5 batches per hour, which is equivalent to 225 sheets per hour. Press no. 3 is a Williams and White 30-opening plywood press with a rated capacity of 20,000 square feet per hour.

Plywood presses emit fugitive VOC and PM_{10} as sheets of wood veneer are pressed together using hot platens; they do not emit NOx or SO_2. Plywood assembly operations are located within a single large building. Because plywood presses are co-located with other process units, it is likely that the limited plywood press emissions data that have been collected by the National Council for Air and Stream Improvement (NCASI)[3] also includes fugitive emissions from other different types of process units in the same building. Nevertheless, estimated plywood press PM_{10} emissions are fairly small (less than 20 tons per year).

Plywood manufacturing facilities are subject to the NESHAP for Plywood and Composite Wood Products (PCWP) at 40 CFR 63, Subpart DDDD. Although veneer dryers are subject to standards, the USEPA determined that emissions from plywood presses were not amenable to capture and control and did not set any standards for these sources. The USEPA distinguished emissions control requirements for plywood presses from other reconstituted wood products presses (e.g., particleboard, oriented strand board, and medium density fiberboard) "because of different emissions characteristics and the fact that plywood presses are often manually loaded and unloaded (unlike reconstituted wood product presses that have automated loaders and unloaders)."[4] By virtue of issuing emission control standards only for reconstituted wood products presses, the USEPA essentially determined that emissions capture and control is practicable for these types of presses, but not plywood presses. In the September 2019 PCWP NESHAP risk and technology review proposal, the USEPA did not propose to add standards for plywood presses.

The USEPA Reasonably Available Control Technology/Best Available Control Technology/ Lowest Achievable Emission Rate, or simply "RBLC," database includes no entries for plywood presses with add-on emissions controls. The USEPA's database of emission sources that was developed for the risk and technology review of the PCWP NESHAP indicates that no plywood presses at HAP major sources are enclosed or controlled.

Plywood presses are fugitive sources whose emissions pass through the building roof vents above the presses. Existing vents in the vicinity of these process units are not intended to quantitatively capture and exhaust gaseous emissions specifically from the plywood presses; rather, they are strategically placed to exhaust emissions from the building. When the process and building ventilation layouts were designed, the possibility of emissions capture or testing was not contemplated.

Plywood presses are not enclosed because they need to be accessed by employees. Plywood manufacturing facilities typically have one layup line that feeds multiple presses. On the layup line, layers of dried veneer are laid down in alternating directions with resin applied between each layer. At

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[3] NCASI is an association organized to serve the forest products industry as a center of excellence providing unbiased, scientific research and technical information necessary to achieve the industry's environmental and sustainability goals.

[4] USEPA, "National Emission Standards for Hazardous Air Pollutants for Plywood and Composite Wood Products Manufacturing—Background Information for Final Standards." February 2004.

the end of the line, the layered mat is trimmed, stacked, and moved to the press infeed area for each press. This configuration requires more operating space and manual input than other wood products manufacturing processes. Plywood presses are batch processes and loading the press is manually assisted (the press charger is manually loaded). Operators must be able to observe press operation to check that the press is properly loaded. Pressed plywood is removed from the area, typically by using a forklift. Adding an enclosure to capture emissions is not feasible because it would disrupt operation of the press (both infeed and outfeed), inhibit maintenance activities, and create unsafe working conditions for employees (isolation, heat, and emissions).

As detailed above, there are no technically feasible control options to capture or control plywood press PM_{10} emissions. Therefore, the plywood presses were excluded from further evaluation in the PM_{10} Analysis.

2.1.4 Pneumatic Conveyors (4CON)

The Pneumatic Conveyor emissions unit represents a collection of miscellaneous conveyors, cyclones, and target boxes used to handle and transport materials around the facility. Transported materials include chips, sawdust, plytrim, and sanderdust from both off-site sources and on-site activities. Individual process units, grouped within the Pneumatic Conveyor emissions unit, include the following:

- T&G saw cyclone no. 5
- T&G saw cyclone no. 4
- Veneer saw cyclone no. 3
- Hogged fuel blow pipe
- Target box no. 2
- Target box no. 3
- Sanderdust pneumatic conveyor

Only the emission units that meet the threshold of 90 percent contribution to the total facility PM_{10} emissions rate are listed above. Each emissions unit meeting the 90 percent contribution threshold is discussed in more detail in the following subsections.

2.1.4.1 T&G Saw Cyclone no. 5

T&G saw cyclone no. 5 (process unit CY5 in the existing permit) controls PM emissions generated by use of the T&G saw and detail saw in the main production building. PM emissions (i.e., plytrim residuals) enter into T&G saw cyclone no. 5 where centrifugal forces are imparted on larger-diameter particles in the conical chamber. The centrifugal forces influence the larger-diameter particles to move toward the cyclone walls, resulting in collection of plytrim residuals at the bottom of the cone. Collected plytrim residuals are then routed to T&G saw cyclone no. 4.

Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone. Exhaust parameters for the T&G saw cyclone are summarized in Section 2.4.

2.1.4.2 T&G Saw Cyclone no. 4

T&G saw cyclone no. 4 (process unit CY4 in the existing permit) routes collected plytrim residuals from T&G saw cyclone no. 5 to the downstream Plytrim Baghouse. The operation and control mechanisms of T&G saw cyclone no. 4 are identical to the descriptions presented in Section 2.1.4.1, except that collected plytrim residuals (i.e., particle fallout from the cone) are routed to the Plytrim Baghouse.

Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone. Exhaust parameters for T&G saw cyclone no. 4 are summarized in Section 2.4.

2.1.4.3 Veneer Saw Cyclone no. 3

The Veneer saw cyclone no. 3 (process unit CY3 in the existing permit) controls PM emissions generated by use of the core saw in the veneer storage building. The operation and control mechanisms of Veneer saw cyclone no. 3 are identical to the descriptions presented in Section 2.1.4.1, except that collected plytrim residuals (i.e., particle fallout from the cone) combine with plytrim residuals from T&G saw cyclone no. 4, and are routed to the Plytrim Baghouse.

Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone. Exhaust parameters for the Veneer saw cyclone no. 4 are summarized in Section 2.4.

2.1.4.4 Hogged Fuel Blow Pipe

The hogged fuel blow pipe (process unit BP1 in the existing permit) is a fully sealed, high-pressure blow line delivering hogged fuel across the facility. Hogged fuel is loaded into the blow pipe, using an enclosed chute with an airlock from the hog. Loaded hogged fuel is routed to either target box no. 2 or target box no. 3 (target box nos. 2 and 3 are discussed in more detail in the following subsections).

Based on communications with the facility, target box no. 3 is the actual point of emissions, and the hogged fuel blow pipe does not represent an emissions unit. Hence, the hogged fuel blow pipe is not an emissions unit and is shown incorrectly in the existing permit. Therefore, the hogged fuel blow pipe was excluded from further evaluation in the Analysis. Note that the permit error will be corrected in the next permitting cycle for the facility.

2.1.4.5 Target Box no. 2

Hogged fuel is routed primarily to target box no. 2 (process unit TB2 in the existing permit) via the hogged fuel blow pipe. Target box no. 2 is used to deliver hogged fuel into the hogged fuel silo. Based on communications with the facility, target box no. 2 is fully sealed to the top of the hogged fuel silo and does not emit. Hence, target box no. 2 is not an emissions unit and is shown incorrectly in the existing permit. Therefore, target box no. 2 was excluded from further evaluation in the Analysis. Note that the permit error will be corrected in the next permitting cycle for the facility.

2.1.4.6 Target Box no. 3

Hogged fuel is also routed to target box no. 3 (process unit TB3 in the existing permit) via the hogged fuel blow pipe. Target box no. 3 is used only to drop hogged fuel to a pile, adjacent to the hogged fuel loading area, when the silo is completely full. Exhaust parameters for target box no. 3 are presented in Section 2.4.

2.1.4.7 Sanderdust Pneumatic Conveyor

PM emissions (i.e., sanderdust) generated by the plywood sander are collected in two Torit baghouses. Collected sanderdust is loaded onto the sanderdust pneumatic conveyor (no process unit ID is presented in the existing permit) through rotary airlocks located at the bottom of each baghouse. The sanderdust pneumatic conveyor is used to route sanderdust to the downstream bin vent baghouse located atop the sanderdust truck loading bin. Collected sanderdust from the bin vent baghouse is dropped into the sanderdust truck loading bin via the attached rotary air lock. Exhaust parameters for the sanderdust pneumatic conveyor are presented in Section 2.4.

2.1.5 Materials Handling (2MT)

The Materials Handling emissions unit consists of miscellaneous equipment used to handle hogged fuel, bark, chips, sawdust, and sanderdust, including conveying these materials around the facility. Individual process units, grouped in the Materials Handling emissions unit, include the following:

- Hogged fuel pile-fuel loader
- Chip loading bin and associated pile
- Hogged fuel truck unloading ramp
- Hogged fuel and bark bins
- Plytrim truck loading bin

Only the emission units that meet the threshold 90 percent contribution to the total emissions rate for the facility are listed above. Each emission unit is described in more detail in the relevant section below.

2.1.5.1 Hogged Fuel Pile-Fuel Loader

A wheel loader, referred to in the existing permit as hogged fuel pile-fuel loader (process unit FL1), is used to transport hog fuel from the pile created by target box no. 3 and the hogged fuel truck dump area. The hogged fuel pile-fuel loader delivers stockpiled hogged fuel to the hog fuel conveyor, which feeds into the hogged fuel silo. Fugitive emissions are generated as the wheel loader transports material to the covered hogged fuel conveyor. Control of the fugitive particulate emissions generated by the wheel loader activities is considered to be technically infeasible. Therefore, the hogged fuel pile-fuel loader was excluded from further evaluation in the Analysis.

2.1.5.2 Chip Loading Bin and Associated Pile

There are three chip loading bins (process units B3, B4, and B5 in the existing permit) and a chip pile located in close proximity to the veneer production building. Two chip loading bins are fed by two open box chain conveyors, referred to in the existing permit as the chip conveyor and the bark conveyor. The third chip loading bin is fed by target box no. 1 (process unit TB1 in the existing permit). The actual point of emissions for the chip loading bins is limited to the dropping of chips into trucks (emissions generated by the chip and bark conveyors and target box no. 1 are accounted for elsewhere) and the cleanup of the associated pile.

As trucks drive under the chip loading bins, the bin door bottoms open, and green chips are loaded. The open sides of the bin doors and height of the truck sides provide adequate protection from wind, helping to limit fugitive emissions. Access material is dropped to the adjacent chip pile when trucks overload or have to make specific weight targets. This pile is periodically removed by a front-end loader, which feeds a nearby conveyor that is used to route chips to the hogged fuel bin (process unit B2 in the existing permit) as needed. It is important to note that the chips have high moisture contents resulting in minimal emissions of fine particulate.

The loading of trucks via the chip loading bins and the process of clearing the pile represent sources of fugitive particulate emissions. Control of fugitive particulate emissions generated by each emissions unit is considered to be technically infeasible, since capture and collection cannot reasonably be achieved without altering truck and/or worker access (e.g., creating safety concerns). Based on the fugitive nature of each emissions unit, the chip loading bins and associated pile emissions unit were excluded from further evaluation in the Analysis.

2.1.5.3 Hogged Fuel Truck Unloading Ramp

The hogged fuel truck unloading ramp (process unit HFR1 in the existing permit) is used for unloading hogged fuel delivered in semi-trucks from off-site sources. As the semi-trucks drive onto the unloading ramp, hogged fuel is dumped from the trucks to an adjacent hogged fuel storage pile. Enclosure and control of fugitive particulate emissions is considered to be technically infeasible since the semi-trucks dump from the unloading ramp and adequate space is required for access and unloading activities. Therefore, the hogged fuel truck unloading ramp was excluded from further evaluation in the Analysis.

2.1.5.4 Hogged Fuel and Bark Bins

The hogged fuel and bark bins (process unit B2 in the existing permit) are used to load material into outbound trucks near the veneer production building. Both bins are used only when the hogged fuel blow pipe is down for maintenance purposes. The normal operation is to route bark through the hogged fuel blow pipe to the hogged fuel silo or pile via target box nos. 2 and 3, respectively.

The hogged fuel and bark bin can also be supplied green chips by the adjacent conveyor. This conveyor receives green chips from the front-end loader used to periodically to clean up the pile identified in Section 2.1.5.2.

Similar to Section 2.1.5.2, the loading of trucks, via the hogged fuel and bark bins, represents a source of fugitive particulate emissions. Control of fugitive particulate emissions generated by use of the bins is considered to be technically infeasible, since capture and collection cannot reasonably be achieved. Based on the fugitive nature of the emissions unit and the infrequent use of the bins, the hogged fuel and bark bins emissions unit was excluded from further evaluation in the Analysis.

2.1.5.5 Plytrim Truck Loading Bin

The plytrim truck loading bin (process unit B8 in the existing permit) is used to drop plytrim residuals into outbound trucks to be hauled off site. Plytrim residuals are delivered to the bin via an airlock attached to the Plytrim Baghouse located directly on top of the plytrim truck loading bin.

Similar to the description provided in Section 2.1.5.2, the loading of trucks, via the plytrim truck loading bin, represents a source of fugitive particulate emissions. Control of fugitive particulate emissions generated by use of the bins is considered to be technically infeasible, since capture and collection cannot reasonably be achieved without altering truck and/or worker access (e.g., creating safety concerns). Therefore, the plytrim truck loading bin was excluded from further evaluation in the Analysis.

2.1.6 Paved and Unpaved Roads (6WE)

The paved roads emissions unit is representative of fugitive emissions generated by vehicle traffic on paved and unpaved roads on facility property. The facility conducts periodic sweeping and watering on on-site roads as preventative dust-control measures. Further control of the paved roads emissions unit is considered to be technically infeasible since capture and collection of emissions cannot reasonably be achieved. Therefore, the paved roads emissions unit was excluded from further evaluation in the Analysis.

2.2 Sources of NO_X Emissions

A summary of the selected emission units and associated NO_X emission rates to be evaluated in the Analysis is presented in Table 2-2 (attached). As shown in the table, only the hogged fuel boiler is included as a source for further evaluation in the Analysis. See Section 2.1.1 for a description of the hogged fuel boiler emissions unit and associated existing control devices.

2.3 Sources of SO_2 Emissions

A summary of the selected emission units and associated SO_2 emission rates to be evaluated in the Analysis is presented in Table 2-3 (attached). As shown in the table, only the hogged fuel boiler is included as a source for further evaluation in the Analysis. See Section 2.1.1 for a description of the hogged fuel boiler emissions unit and associated existing control devices.

2.4 Emission Unit Exhaust Parameters

A summary of the emissions unit exhaust parameters to be evaluated further in this Analysis is presented in Table 2-4 (attached). Emission units identified in the preceding sections as infeasible for control or otherwise exempt are not presented. These emissions units will not be evaluated further in this Analysis.

3 REGIONAL HAZE FOUR FACTOR ANALYSIS METHODOLOGY

This Analysis has been conducted consistent with the Federal Guidance Document, which outlines six steps to be taken when addressing the four statutorily required factors included in the Analysis. These steps are described in the following sections.

3.1 Step 1: Determine Emission-Control Measures to Consider

Identification of technically feasible control measures for visibility-impairing pollutants is the first step in the Analysis. While there is no regulatory requirement to consider all technically feasible measures, or any specific controls, a reasonable set of measures must be selected. This can be accomplished by identifying a range of options, which could include add-on controls, work practices that lead to emissions reductions, operating restrictions, or upgrades to less efficient controls, to name a few.

3.2 Step 2: Selection of Emissions

Section 2 details the method for determining the emission units and emission rates to be used in the Analysis. Potential to emit emission rates were obtained from the existing permit review report.

3.3 Step 3: Characterizing Cost of Compliance (Statutory Factor 1)

Once the sources, emissions, and control methods have all been selected, the cost of compliance is estimated. The cost of compliance, expressed in units of dollars per ton of pollutant controlled ($/ton), describes the cost associated with the reduction of visibility-impairing pollutants. Specific costs associated with operation, maintenance, and utilities at the facility are presented in Table 3-1 (attached).

The Federal Guidance Document recommends that cost estimates follow the methods and recommendations in the Control Cost Manual. This includes the recently updated calculation spreadsheets that implement the revised chapters of the Control Cost Manual. The Federal Guidance Document recommends using the generic cost estimation algorithms detailed in the Control Cost Manual in cases where site-specific cost estimates are not available.

Additionally, the Federal Guidance Document recommends using the Control Cost Manual in order to effect an "apples-to-apples" comparison of costs across different sources and industries.

3.4 Step 4: Characterizing Time Necessary for Compliance (Statutory Factor 2)

Characterizing the time necessary for compliance requires an understanding of construction timelines, which include planning, construction, shake-down and, finally, operation. The time that is needed to complete these tasks must be reasonable, and does not have to be "as expeditiously as practicable…" as is required by the Best Available Retrofit Technology regulations.

3.5 Step 5: Characterize Energy and Non-air Environmental Impacts (Statutory Factor 3)

Both the energy impacts and the non-air environmental impacts are estimated for the control measures that were costed in Step 3. These include estimating the energy required for a given control method, but do not include the indirect impacts of a particular control method, as stated in the Federal Guidance Document.

The non-air environmental impacts can include estimates of waste generated from a control measure and its disposal. For example, nearby water bodies could be impacted by the disposed-of waste, constituting a non-air environmental impact.

3.5.1 Step 6: Characterize Remaining Useful Life of Source (Statutory Factor 4)

The Federal Guidance Document highlights several factors to consider when characterizing the remaining useful life of the source. The primary issue is that often the useful life of the control measure is shorter than the remaining useful life of the source. However, it is also possible that a source is slated to be shut down well before a control device would be cost effective.

4 PM_{10} ANALYSIS

The Analysis for PM_{10} emissions follows the six steps previously described in Section 0.

4.1 Step 1—Determine PM_{10} Control Measures for Consideration

4.1.1 Baghouses

Baghouses, or fabric filters, are common in the wood products industry. In a fabric filter, flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to collect on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are one of the most common forms of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. The accumulated particles are periodically removed from the filter surface by a variety of mechanisms and are collected in a hopper for final disposition.

Typical new equipment design efficiencies are between 99 and 99.9 percent. Several factors determine fabric filter collection efficiency. These include gas filtration velocity, particle characteristics, fabric characteristics, and the cleaning mechanism. In general, collection efficiency increases with decreasing filtration velocity and increasing particle size. Fabric filters are generally less expensive than ESPs and they do not require complicated control systems. However, fabric filters are subject to plugging for certain exhaust streams and do require maintenance and inspection to ensure that plugging or holes in the fabric have not developed. Regular replacement of the filters is required, resulting in higher maintenance and operating costs.

Certain process limitations can affect the operation of baghouses in some applications. For example, exhaust streams with very high temperatures (i.e., greater than 500°F) may require specially formulated filter materials and/or render baghouse control infeasible. Additional challenges include the particle characteristics, such as materials that are "sticky" and tend to impede the removal of material from the filter surface. Exhaust gases that exhibit corrosive characteristics may also impose limitations on the effectiveness of baghouses. There is also the concern for combustible wood dust creating a potential spark hazard within the baghouse (i.e., generating embers within the collector). As a result, a spark detection/extinguishment system will be necessary in certain wood product applications. In wood products applications it is expected that particle characteristics, specifically particle and exhaust moisture content, may limit the feasibility on implementation. However, for some sources, baghouses are considered technically feasible.

4.1.2 Wet Venturi Scrubbers

Wet scrubbers remove particulate from gas streams primarily by inertial impaction of the particulate onto a water droplet. In a venturi scrubber, the gas is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity, causing the water to shear into fine droplets. Particles in the gas stream then impact the water droplets. The entrained water droplets are subsequently removed from the gas stream by a cyclonic separator. Venturi scrubber control efficiency increases with increasing pressure drops for a given particle size. Control efficiency increases with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Control efficiencies are typically around 90 percent for particles with a diameter of 2.5 microns or larger.

It is important to note that although wet scrubbers mitigate air pollution concerns, they also generate a water pollution concern. The effluent wastewater and wet sludge stream created by wet scrubbers requires that the operating facility have a water treatment system and subsequent disposal system in place. These consequential systems increase the overall cost of wet scrubbers and cause important environmental impacts to consider.

As wet scrubbers become saturated with a pollutant it is necessary to discharge (blowdown) some scrubber liquid and add fresh water. A water treatment system of suitable size is necessary to handle the scrubber blowdown. The Glendale facility is not connected to a city sewer system. The facility is reliant on a septic system. The amount of scrubber blowdown that would be created for an appropriately sized wet scrubber would likely overwhelm the septic system.

As a result, a wet scrubber system is considered technically infeasible for this facility location.

4.1.3 Electrostatic Precipitator

ESPs are used extensively for control of PM emissions. An ESP is a particulate control device that uses electrical force to move particles entrained with a gas stream onto collection surfaces. An electrical charge is imparted on the entrained particles as they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the corona that charges the particles, thereby allowing for their collection on the oppositely charged collector walls. Due to these electrical forces, there is high concern for combustible wood dust creating a potential spark hazard within an ESP (i.e., generating embers within the collector). As a result, a spark detection/extinguishment system will be necessary in order to mitigate the potential for deflagration events, at a minimum. Prior to an actual installation, a vendor evaluation will be necessary to determine if there are site-specific hazards that will preclude this control option due to safety concerns. Under the current timeline, a vendor inspection was not possible by an outside ESP vendor prior to submitting this Analysis.

In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. Instead of the collection hoppers used by dry ESPs, wet ESPs utilize a drainage system and water treatment of some sort. In dry ESPs, the collectors are knocked, or "rapped," by various mechanical means to dislodge the collected particles, which slide downward into a hopper for collection.

Typical control efficiencies for new installations are between 99 and 99.9 percent. Older existing equipment has a range of actual operating efficiencies of 90 to 99.9 percent. While several factors determine ESP control efficiency, ESP size is the most important because it determines the exhaust residence time; the longer a particle spends in the ESP, the greater the chance of collecting it. Maximizing electric field strength will maximize ESP control efficiency. Control efficiency is also affected to some extent by particle resistivity, gas temperature, chemical composition (of the particle and gas), and particle size distribution.

Similar to wet scrubber control systems, wet ESPs also create a water pollution concern. The effluent wastewater and wet sludge stream created by the wet ESP requires the operating facility to have an appropriately sized water treatment system and subsequent disposal system in place. The overall amount of wastewater generated by operating in the wet ESP may likely overwhelm the septic system.

As a result, while a dry ESP is considered a technically feasible control device option, a wet ESP is considered technically infeasible for this facility location.

4.2 Step 2—Selection of Emissions

See Sections 2.1 for descriptions of the PM_{10} emission units and emission rates selected for the Analysis.

4.3 Step 3—Characterizing Cost of Compliance

Tables 4-2 and 4-3 (attached) present the detailed cost analyses of the technically feasible PM_{10} control technologies included in the Analysis. Note the sanderdust pneumatic conveyor is already controlled by the bin vent baghouse and therefore, was not included in Table 4-2 (e.g., baghouse cost effectiveness derivation table). A summary of the cost of compliance, expressed in $/ton, is shown below in Table 4-1:

Table 4-1
Cost of Compliance Summary for PM_{10}

Emissions Unit	Process Unit ID	Cost of Compliance ($/ton)	
		BH	Dry ESP
Trim Saw Cyclone #5	CY5	$12,818	$14,459
T&G Saw Cyclone #4	CY4	$23,234	$26,214
Veneer Saw Cyclone #3	CY3	$58,414	$65,500
Target Box #3	TB3	$78,615	$94,268
Sanderdust Pneumatic Conveyor	--	--	$101,309

4.4 Step 4—Characterizing Time Necessary for Compliance

Several steps will be required before the control device is installed and fully operational. After selection of a control technology, all of the following will be required: permitting, equipment procurement, construction, startup and a reasonable shakedown period, and verification testing. It is anticipated that it will take up to 18 months to achieve compliance.

4.5 Step 5—Characterizing the Energy and Non-air Environmental Impacts

4.5.1 Energy Impacts

Energy impacts can include electricity and/or supplemental fuel used by a control device. Electricity use can be substantial for large projects if the control device uses large fans, pumps, or motors. Similarly, processes based on thermal oxidation may use significant amounts of fossil fuels, which can lead to economic impacts as well as climate change impacts.

Baghouse control systems require significant electricity use to operate the powerful fans required to overcome the pressure drop across the filter bags. Dry ESPs are expected to require even more electricity than baghouses, since high-voltage electricity is required for particle collection and removal. Dry ESPs also require powerful fans to maintain exhaust flow through the system.

4.5.2 Environmental Impacts

Expected environmental impacts for baghouses and dry ESPs include the management of materials collected by the control devices. For sources where this material is clean wood residuals, it may be possible to reuse the material in the production process. However, collected materials that are degraded or that contain potential contaminants would be considered waste materials requiring disposal at a landfill.

While none of the control technologies evaluated in the PM_{10} Analysis would require the direct consumption of fossil fuels, another, less quantifiable, impact from energy use may result from producing the electricity (i.e., increased greenhouse gases and other pollutant emissions). In addition, where fossil fuels are used for electricity production, additional impacts are incurred from the mining/drilling and use of fossil fuels for combustion.

4.6 Step 6—Characterize Remaining Useful Life

It is anticipated that the remaining life of the emissions units, as outlined in the Analysis, will be longer than the useful life of the technically feasible control systems. No emissions units are subject to an enforceable requirement to cease operation. Therefore, in accordance with the Federal Guidance Document, the presumption is that the control system would be replaced by a like system at the end of its useful life. Thus, annualized costs in the Analysis are based on the useful life of the control system rather than the useful life of the emissions units.

5 NOX ANALYSIS

The Analysis for NO_X emissions follows the six steps previously described in Section 0.

5.1 Step 1—Determine NO_X Control Measures for Consideration

5.1.1 Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) systems have been widely employed for biomass combustion systems. SNCR is relatively simple because it utilizes the combustion chamber as the control device reactor, achieving control efficiencies of approximately 25 to 70 percent. SNCR systems rely on the reaction of ammonia and nitric oxide (NO) at temperatures of 1,550°F to 1,950°F to produce molecular nitrogen and water, common atmospheric constituents, in the following reaction:

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

In the SNCR process, the ammonia or urea is injected into the combustion chamber, where the combustion gas temperature is in the proper range for the reaction. Relative to catalytic control devices, SNCR is inexpensive and easy to install, particularly in new applications where the injection points can be placed for optimum mixing of ammonia and combustion gases. The reduction reaction between ammonia and NO is favored over other chemical reactions at the appropriate combustion temperatures and is, therefore, a selective reaction. One major advantage of SNCR is that it is effective in combustion gases with a high particulate loading. Sanderdust combustion devices can produce exhaust that has a very high particulate loading rate from ash carryover to the downstream particulate control device. With use of SNCR, the particulate loading is irrelevant to the gas-phase reaction of the ammonia and NO.

One disadvantage of SNCR, and any control systems that rely on the ammonia and NO reaction, is that excess ammonia (commonly referred to as "ammonia slip") must be injected to ensure the highest level of control. Higher excess ammonia generally results in a higher NOx control efficiency. However, ammonia is also a contributor to atmospheric formation of particulate that can contribute to regional haze. Therefore, the need to reduce NOx emissions must be balanced with the need to keep ammonia slip levels acceptable. Careful monitoring to ensure an appropriate level of ammonia slip, not too high or too low, is necessary.

Additionally, in applications where SNCR is retrofitted to an existing combustion chamber (i.e., an existing boiler), substantial care must be used when selecting injection locations. This is because proper mixing of the injected ammonia cannot always be achieved in a retrofit, possibly because of limited space inside the boiler itself. For this reason, in retrofit applications it is common to achieve control efficiencies toward the lower end (25%) of the SNCR control efficiency range previously mentioned.

5.1.2 Selective Catalytic Reduction and Hybrid Systems

Unlike SNCR, selective catalytic reduction (SCR) reduces NOx emissions with ammonia in the presence of a catalyst. The major advantages of SCR technology are the higher control efficiency (70% to 90%) and the lower temperatures at which the reaction can take place (400°F to 800°F, depending on the catalyst selected). SCR is widely used for combustion processes, such as those using natural gas turbines, where the type of fuel produces a relatively clean combustion gas. In an SNCR/SCR hybrid system, ammonia or urea is injected into the combustion chamber to provide the initial reaction with NOx emissions, followed by a catalytic (SCR) section that further enhances the reduction of NOx emissions. The primary reactions that take place in the presence of the catalyst are:

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

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

$$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O$$

SCR is not widely used with wood-fired combustion units because of the amount of particulate that is generated by the combustion of wood. If not removed completely, the particulate can cause plugging in the catalyst and can coat the catalyst, reducing the surface area for reaction. Another challenge with wood-fired combustion is the presence of alkali metals such as sodium and potassium, which are commonly found in wood but not in fossil fuels. Sodium and potassium will poison catalysts, and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorus and arsenic.

Because of the likelihood of catalyst deactivation through particulate plugging and catalyst poisoning, SCR and SNCR/SCR hybrid systems are considered to be technically infeasible for control of NOx emissions from wood-fired combustion units.

5.1.3 Low NOx Burner

Low NO_X burners are a viable technology for a number of fuels, including sanderdust and natural gas. Low NO_X burner technology is used to moderate and control, via a staged process, the fuel and air mixing rate in the combustion zone. This modified mixing rate reduces the oxygen available for thermal NO_X formation in critical NO_X formation zones, and/or decreases the amount of fuel burned at peak flame temperatures. These techniques are also referred to as staged combustion or sub-stoichiometric combustion to limit NO_X formation.

Combustion in hogged fuel boilers commonly occurs on grates, including the Dutch-oven-type hogged fuel boiler at the facility, and does not utilize the types of burners typically employed for low NO_X burner applications. Potential reductions in NO_X emissions from these types of boilers (without add-on controls) are limited by the boiler furnace geometry, air flow controls, and burner zone stoichiometry, making retrofitting applications difficult. The hogged fuel boiler at the facility is regularly inspected for fine-tuning and/or routine maintenance of the boiler systems. As a result, it is expected that the hogged fuel boiler is already optimized for NO_X performance.

In order to achieve effective NO_X reductions from low NO_X burners, a complete replacement of the hogged fuel boiler system, including fans, air control systems, firebox, and steam generating tubes, would likely be required. The Federal Guidance Document identifies several criteria for selecting control measures in the Analysis, including emission reductions through improved work practices, retrofits for sources with no existing controls, and upgrades or replacements for existing, less effective controls. None of these criteria identify or recommend whole replacement of emission units. Based on the challenges with retrofitting the hogged fuel boiler and the Federal Guidance Document criteria, low NO_X burners for hogged fuel boilers were excluded from further consideration in the Analysis.

5.2 Step 2—Selection of Emissions

See Sections 2.2 for descriptions of the NO_X emission units and emission rates selected for the Analysis.

5.3 Step 3—Characterizing Cost of Compliance

Table 5-1 presents the detailed cost analysis of the only technically feasible NO_X control technology (e.g., SNCR) included in the Analysis. The cost estimate is based on a heated urea-based injection system, instead of aqueous ammonia injection, because of storage safety concerns. The cost of compliance for the SNCR installation on the hogged fuel boiler is $12,265 per ton of NO_X emissions controlled.

5.4 Step 4—Characterizing Time Necessary for Compliance

Several steps will be required before the control device is installed and fully operational. After selection of a control technology, all of the following will be required: permitting, equipment procurement, construction, startup and a reasonable shakedown period, and verification testing. It is anticipated that it will take up to 18 months to achieve compliance.

5.5 Step 5—Characterizing Energy and Non-air Environmental Impacts

5.5.1 Energy Impacts

Direct energy impacts will result from the use of SNCR control systems. Energy use (e.g. electricity use) is limited to the operation of pumps for urea injection into the SNCR and the heating of the urea storage tank. As a result, direct energy impacts are expected to be minimal. SNCR systems also consume fossil fuels, primarily natural gas, during the ammonia production process, and in order to mitigate the increased moisture loads caused by the urea injection in the flue gas.

5.5.2 Environmental Impacts

SNCR units require the use of urea (or aqueous ammonia) injection in the exhaust stream. Any unreacted excess ammonia in the exhaust stream (i.e., ammonia slip) will be released to the atmosphere. Ammonia slip to the atmosphere is a contributor to fine particle formation, which further exacerbates the regional haze issue; ammonia is also considered to be a toxic air contaminant with associated human health risks, and is regulated under the Cleaner Air Oregon Program. Hence, there is a trade-off between maximizing NO_X emission reductions and minimizing the potential for ammonia slip.

5.6 Step 6—Characterize Remaining Useful Life

It is anticipated that the remaining life of the emissions units, as outlined in the Analysis, will be longer than the useful life of the technically feasible control systems. No emissions units are subject to an enforceable requirement to cease operation. Therefore, in accordance with the Federal Guidance Document, the presumption is that the control system would be replaced by a like system at the end of its useful life. Thus, annualized costs in the Analysis are based on the useful life of the control system rather than the useful life of the emissions units.

6 SO_2 ANALYSIS

The Analysis for SO_2 emissions follows the six steps previously described in Section 0.

6.1 Step 1—Determine SO_2 Control Measures for Consideration

6.1.1 Dry Sorbent Injection

SO_2 scrubbers are control devices typically used on stationary utility and industrial boilers, especially those combusting high sulfur fuels such as coal or oil. SO_2 scrubbers are not common for wood-fired boiler applications because of the inherent low sulfur content of the fuel.

SO_2 scrubbers use a reagent to absorb, neutralize, and/or oxidize the SO_2 in the exhaust gas, depending on the selected reagent. In dry sorbent injection systems, powdered sorbents are pneumatically injected into the exhaust gas to produce a dry solid waste. As a result, use of dry sorbent injection systems requires downstream particulate control devices to remove the dry solid waste stream. This waste product, a mixture of fly ash and the reacted sulfur compounds, will require landfilling or other waste management. For sources with existing particulate control devices, retrofitting dry sorbent injection onto existing systems will increase the volume of fly ash and solid waste generated by the existing system.

Overall performance depends on the sorbent selected for injection and the exhaust gas temperature at the injection location. These parameters are driven in large part by the specific combustion unit configuration and space limitations. Control efficiencies for dry sorbent injection systems, including retrofit applications, range between 50 percent and 80 percent for control of SO_2 emissions. While higher control efficiencies can be achieved with dry sorbent injection in new installations or with wet SO_2 scrubber systems, the ease of installation and the smaller space requirements make dry sorbent injection systems preferable for retrofitting.

Dry sorbent injection systems introduce PM emissions into the exhaust stream, as mentioned above. This will cause increases to the particulate inlet loading of downstream particulate control devices. For retrofit applications, it is likely that modification of the downstream existing particulate control device will be necessary in order to accommodate the increased particulate inlet loading. It is anticipated that this increased loading cannot be accommodated solely through modifications to the existing control device. Assuming that this is the case, additional particulate controls will be required, resulting in cost increases and further energy and environmental impacts.

In addition, dry sorbent injection systems are commonly applied to high sulfur content fuel combustion systems, such as coal-fired boilers but not wood-fired boilers. The sulfur content of wood is quite low when compared to coal. It is also not certain that the control efficiency range, stated above, would be achievable when implemented on the emission units included in this SO_2 Analysis because of the low concentration of sulfur in the exhaust streams.

Therefore, the installation of dry sorbent injection systems on the emission units included in this SO_2 Analysis is not considered to be a feasible control option. Moreover, the potential for higher particulate emissions, which contribute to visibility issues, suggests that dry sorbent injection should not be assessed in this Analysis.

6.2 Step 2—Selection of Emissions

See Sections 2.3 for a description of the SO_2 emission units and emission rates selected in the Analysis.

6.3 Step 3—Characterizing Cost of Compliance

No technically feasible control technologies were identified for potential control of SO_2 emissions. Therefore, the cost of compliance is not applicable to this Analysis.

6.4 Step 4—Characterizing Time Necessary for Compliance

No technically feasible control technologies were identified for potential control of SO_2 emissions. Therefore, the time necessary for compliance is not applicable to this Analysis.

6.5 Step 5—Characterizing Energy and Non-air Environmental Impacts

Since no technically feasible control technologies were identified for SO_2 emissions, there are no energy and non-air environmental impacts to characterize.

6.6 Step 6—Characterize Remaining Useful Life

No technically feasible control technologies were identified for SO_2 emissions; therefore, no characterization of the remaining useful life is necessary for the Analysis.

7 CONCLUSION

This report presents cost estimates associated with installing control devices at the Glendale facility in order to reduce visibility-impairing pollutants in Class I areas, and provides the Four Factor Analysis conducted consistent with available DEQ and USEPA guidance documents. Swanson believes that the above information meets the state objectives and is satisfactory for the DEQ's continued development of the SIP as a part of the Regional Haze program.

LIMITATIONS

The services undertaken in completing this report were performed consistent with generally accepted professional consulting principles and practices. No other warranty, express or implied, is made. These services were performed consistent with our agreement with our client. This report is solely for the use and information of our client unless otherwise noted. Any reliance on this report by a third party is at such party's sole risk.

Opinions and recommendations contained in this report apply to conditions existing when services were performed and are intended only for the client, purposes, locations, time frames, and project parameters indicated. We are not responsible for the impacts of any changes in environmental standards, practices, or regulations subsequent to performance of services. We do not warrant the accuracy of information supplied by others, or the use of segregated portions of this report.

TABLES

Table 2-1
PM_{10} Evaluation for Regional Haze Four Factor Analysis
Swanson Group Mfg. LLC—Glendale, Oregon

Emission Unit(s) (1)	Emission Unit ID (1)	Current PM_{10} Control Technology (1)	Annual PM_{10} Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Technology Evaluation	Control Technologies to be Evaluated
Trim Saws Cyclone #5 (CY5)	4CON	–	25.8	Yes	–	Baghouse, Wet Venturi Scrubber Electrostatic Precipitator
Hogged Fuel Boiler	1PH	Multiclone & Dry ESP	19.3	No	Source is directly regulated for filterable PM as a surrogate for metal under Area Source Boiler GACT, which became effective after July 31, 2013. Therefore, this source meets EPA guidance for no further analysis.	–
Hog Fuel Pile-Fuel Loader (FL1)	2MT	–	19.1	No	Fugitive source.	–
Chip Loading Bin (B3, B4, and B5) and Pile	2MT	–	17.4	No	Fugitive source.	–
Plywood Presses	P1, P2, P3	–	16.0	No	Accessibility and design limitations make control technically infeasible.	–
T&G Saw Cyclone #4 (CY4)	4CON	–	14.2	Yes	–	Baghouse, Wet Venturi Scrubber Electrostatic Precipitator
Hog Fuel Truck Unloading Ramp (HFR1)	2MT	–	11.7	No	Fugitive source.	–
Paved Roads	6WE	Sweeping & Watering	10.3	No	Fugitive source.	–
Veneer Dryers Fugitives	5VDa	–	9.9	No	Fugitive source and recent reconstruction to minimize fugitives.	–
Hog Fuel and Bark Bins (B2)	2MT	–	7.5	No	Fugitive source and minimal use.	–
Plytrim Truck Loading Bin (B8)	2MT	–	6.0	No	Fugitive source.	–
Veneer Saw Cyclone #3 (CY3)	4CON	–	6.0	Yes	–	Baghouse, Wet Venturi Scrubber Electrostatic Precipitator
Hog Fuel Blow Pipe (BP1)	4CON	–	4.9	No	Not an emissions unit (to be corrected with next permitting cycle).	–
Target Box #2 (TB2)	4CON	–	3.4	No	Not an emissions unit (to be corrected with next permitting cycle).	–
Target Box #3 (TB3)	4CON	–	3.4	Yes	–	Baghouse, Wet Venturi Scrubber Electrostatic Precipitator
Sanderdust Pneumatic Conveyer	4CON	Baghouse	3.1	Yes	–	Wet Venturi Scrubber, Electrostatic Precipitator
All other sources (includes conveyors, veneer dryer RTO, target boxes, truck loading bins, glue mixers, aggregate insignificant)	Varies	Varies by emission unit	22.0	No	This collection of emission units falls below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	–

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

Table 2-2
NO_x Evaluation for Regional Haze Four Factor Analysis
Swanson Group Mfg. LLC—Glendale, Oregon

Emission Unit (1)	Emission Unit ID (1)	Current NO_x Control Technology (1)	Annual NO_x Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Technology Evaluation	Control Technologies to be Evaluated
Hogged Fuel Boiler	1PH	–	71.2	Yes	–	Selective Catalytic Reduction, Selective Non-Catalytic Reduction, Low-NOx Burners
Veneer Dryers	5VD	–	0.4	No	This emission unit falls below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	–

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

Table 2-3
SO_2 Evaluation for Regional Haze Four Factor Analysis
Swanson Group Mfg. LLC—Glendale, Oregon

Emission Unit [(1)]	Emission Unit ID [(1)]	Current SO_2 Control Technology [(1)]	Annual SO_2 Emissions [(2)] (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Technology Evaluation	Control Technologies to be Evaluated
Hogged Fuel Boiler	1PH	–	3.9	Yes	–	Dry Sorbent Injection
Veneer Dryers	5VD	–	0.04	No	This emission unit falls below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	–

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

Table 2-4
Emissions Unit Input Assumptions and Exhaust Parameters
Swanson Group Mfg. LLC—Glendale, Oregon

Emissions Unit ID (1)	Emissions Unit Description (1)	Process Unit ID	Control Evaluation Proposed? (Yes/No)			Heat Input Capacity (MMBtu/hr)	Exhaust Parameters		
							Exit Temperature (°F)	Exit Flowrate	
			PM_{10} (2)	NO_X (3)	SO_2 (4)			(acfm)	(scfm)
1PH	Hogged Fuel Boiler	ESP	No	Yes	Yes	125 (1)	417 (5)	69,633 (5)	31,743 (5)
4CON	Trim Saws Cyclone #5	CY5	Yes	No	No	–	70 (6)	11,500 (7)	10,927 (a)
4CON	T&G Saw Cyclone #4	CY4	Yes	No	No	–	70 (6)	11,500 (7)	10,927 (a)
4CON	Veneer Saw Cyclone #3	CY3	Yes	No	No	–	70 (6)	15,000 (7)	14,253 (a)
4CON	Target Box #3	TB3	Yes	No	No	–	70 (6)	2,300 (7)	2,185 (a)
4CON	Sanderdust Pneumatic Conveyer	–	Yes	No	No	–	70 (6)	1,200 (7)	1,140 (a)

NOTES:

acfm = actual cubic feet per minute.

ESP = electrostatic precipitator.

ft/sec = feet per second.

MMBtu/hr = million British thermal units per hour.

scfm = standard cubic feet per minute.

(a) Exit flowrate (scfm) = (exit flowrate [acfm]) x (1 - [6.73E-06] x [facility elevation above sea level {ft}])$^{5.258}$ x (530) / (460 + [exit temperature {°F}])

Facility elevation above sea level (ft) = 1,437 (8)

REFERENCES:

(1) Information taken from the Review Report for Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.

(3) See Table 2-2, NO_X Evaluation for Regional Haze Four Factor Analysis.

(4) See Table 2-3, SO_2 Evaluation for Regional Haze Four Factor Analysis. Each SO_2 control technology is considered to be technically infeasible.

(5) See source test report, Table 3 "Hog Fuel Boiler," prepared by Bighorn Environmental Air Quality dated April 1, 2014.

(6) The process exhaust is at ambient conditions. Assumes 70°F as representative.

(7) Information provided by Swanson Group Mfg. LLC.

(8) Elevation above sea level obtained from publicly available online references.

Table 3-1
Utility and Labor Rates
Swanson Group Mfg. LLC—Glendale, Oregon

Parameter	Value (units)		
FACILITY OPERATIONS			
Annual Hours of Operation	8,760	(hrs/yr)	(1)
Annual Days of Operation	365	(day/yr)	(1)
Daily Hours of Operation	24	(hrs/day)	(1)
UTILITY COSTS			
Electricity Rate	0.079	($/kWh)	(2)
Natural Gas Rate	2.69	($/MMBtu)	(3)
Water Rate	4.58	($/Mgal)	(a)
Wood Fuel Rate	25.0	($/BDT)	(3)
Landfill Disposal Rate	60.0	($/ton)	(3)
Compressed Air Rate	0.0039	($/Mscf)	(b)
LABOR COSTS			
Maintenance Labor Rate	36.48	($/hr)	(3)
Operating Labor Rate	24.26	($/hr)	(3)
Supervisory Labor Rate	27.99	($/hr)	(3)
Operating Labor Hours per Shift	2	(hrs/shift)	(7)
Maintenance Labor Hours per Shift	1	(hrs/shift)	(7)
Typical Shifts per Day	3	(shifts/day)	(8)

NOTES:

BDT = bone dry ton.

Mgal = thousand gallons.

MMBtu = million British thermal units.

Mscf = thousand standard cubic feet.

MWh = megawatt-hour.

(a) Water cost ($-2019/Mgal) = (water cost [$-2018/Mscf]) / (2018 CEPCI annual index) x (2019 CEPCI annual index)

Water cost ($-2018/gal) = 4.55 (4)
1998 CEPCI annual index = 389.5 (5)
2019 CEPCI annual index = 607.5 (5)

(b) Compressed air cost ($-2019/Mscf) = (compressed air cost [$-1998/Mscf]) / (1998 annual CEPCI index) x (2019 annual CEPCI index)

Compressed air cost ($-1998/Mscf) = 0.0025 (6)
1998 annual CEPCI index = 389.5 (5)
2019 annual CEPCI index = 607.5 (5)

REFERENCES:

(1) Assumes continuous annual operation.
(2) Information provided by Swanson Group Mfg. LLC. Assumes industrial average rate for Pacific Power.
(3) Information provided by Swanson Group Mfg. LLC.
(4) Water and sewer costs obtained from "50 Largest Cities Water & Wastewater Rate Survey" prepared Black & Veatch Management Consulting, LLC dated 2018-2019. See exhibit B, Figure 19. Note this reference was provided in the USEPA Air Pollution Control Cost Manual, Section 3, Chapter 1 "Carbon Adsorbers" calculation spreadsheet.
(5) See Chemical Engineering magazine, CEPCI section for annual indices.
(6) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. Cost presented in section 1.5.1.8 assumed to be representative.
(7) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See table 1.5.1.1 and 1.5.1.3. Conservatively assumes the minimum labor requirement of range presented.
(8) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See table 1.11. Assumes operator shifts per day as representative.

Table 4-2
Cost Effectiveness Derivation for Baghouse Installation
Swanson Group Mfg. LLC—Glendale, Oregon

Process Unit ID	Emissions Unit Description	Input Parameters		Pollutant Removed by Control Device (a) (tons/yr)	Operating Parameter	
		Exhaust Flowrate (1) (acfm)	PM$_{10}$ Annual Emissions Estimate (2) (tons/yr)		Electrical Requirements (4) (kW)	Number of Filter Bags Required (4)
CY5	Trim Saws Cyclone #5	11,500	25.8	25.6	60.4	152
CY4	T&G Saw Cyclone #4	11,500	14.2	14.1	60.4	152
CY3	Veneer Saw Cyclone #3	15,000	6.0	5.91	73.1	196
TB3	Target Box #3	2,300	3.4	3.39	25.2	34

Process Unit ID	Emissions Unit Description	Direct Costs			Total Indirect Costs (d)	Total Capital Investment (e)	Capital Recovery Cost (CRC)				Direct Annual Costs								Total Direct Annual Costs (14)	Total Indirect Annual Costs (o)	Total Annual Cost (p)	Annual Cost Effectiveness (q)
		Purchased Equipment Cost		Total Direct Cost (c)			Control Device (CRC) (f)	Replacement Parts			Operating Labor		Maintenance		Utilities							
		Basic Equip./Services Cost (4)	Total (b)					Filter Bag Cost (4)	Bag Labor Cost (h)	Filter Bag (CRC) (i)	Operator Cost (j)	Supervisor Cost (k)	Labor Cost (j)	Material Cost (14)	Electricity Cost (l)	Compressed Air Cost (m)	Landfill Cost (n)					
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC$_O$	C$_B$	C$_L$	CFC$_B$	--	--	--	--	--	--	--		DAC	IAC	TAC	($/ton)
CY5	Trim Saws Cyclone #5	$105,990	$125,068	$232,618	$56,281	$288,899	$22,693	$2,293	$1,386	$1,083	$53,129	$7,969	$39,946	$39,946	$41,747	$23,569	$1,534		$208,923	$118,843	$327,766	$12,818
CY4	T&G Saw Cyclone #4	$105,990	$125,068	$232,618	$56,281	$288,899	$22,693	$2,293	$1,386	$1,083	$53,129	$7,969	$39,946	$39,946	$41,747	$23,569	$845		$208,234	$118,843	$327,077	$23,234
CY3	Veneer Saw Cyclone #3	$113,861	$134,355	$248,778	$60,460	$309,238	$24,291	$2,948	$1,788	$1,394	$53,129	$7,969	$39,946	$39,946	$50,509	$30,742	$355		$223,989	$121,254	$345,244	$58,414
TB3	Target Box #3	$53,971	$63,686	$125,814	$28,659	$154,473	$12,134	$506	$310	$240	$53,129	$7,969	$39,946	$39,946	$17,421	$4,714	$203		$163,568	$102,907	$266,475	$78,615

See notes and formulas on following page.

Table 4-2 (Continued)
Cost Effectiveness Derivation for Baghouse Installation
Swanson Group Mfg. LLC—Glendale, Oregon

NOTES:

(a) Pollutant removed by control device (tons/yr) = (PM_{10} annual emissions estimate [tons/yr]) x (baghouse control efficiency [%] / 100)

Baghouse control efficiency (%) = 99.0 (3)

(b) Total purchased equipment cost ($) = (1.18) x (basic equipment/services cost [$]); see reference (5).

(c) Total direct cost ($) = (1.74) x (total purchased equipment cost [$]) + (site preparation cost, SP [$]) + (building cost, Bldg. [$]); see reference (5).

Site preparation cost, SP ($) = 15,000 (6)
Building cost, Bldg. ($) = 0 (7)

(d) Total indirect cost ($) = (0.45) x (total purchased equipment cost [$]); see reference (5).

(e) Total capital investment ($) = (total direct cost [$]) + (total indirect cost [$]); see reference (5).

(f) Capital recovery cost of control device ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (8)

Control device capital recovery factor = 0.0786 (g)

(g) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate (%) / 100]^[economic life (yrs)]) / ([1 + (interest rate [%] / 100)]^[economic life (yrs)] - 1); see reference (9).

Interest rate (%) = 4.75 (10)
Baghouse economic life (yr) = 20 (11)
Filter bag economic life (yr) = 4 (12)

(h) Bag replacement labor cost ($) = (total time required to change one bag [min/bag]) x (hr/60 min) x (number of filter bags required [bags]) x (maintenance labor rate [$/hr])

Total time required to change one bag (min/bag) = 15 (13)
Maintenance labor rate ($/hr) = 36.48 (14)

(i) Filter bag capital recovery cost ($) = ([initial filter bag cost ($)] x [1.08] + [bag replacement labor cost ($)]) x (filter bag capital recovery factor); see reference (13).

Filter bag capital recovery factor = 0.2804 (g)

(j) Operator or maintenance labor cost ($) = (staff hours per shift [hrs/shift]) x (staff shifts per day [shifts/day]) x (annual days of operation [days/yr]) x (operator or maintenance labor rate [$/hr])

Operating labor hours per shift [hrs/shift] = 2 (14)
Maintenance labor hours per shift [hrs/shift] = 1 (14)
Shifts per day (shifts/day) = 3 (14)
Annual days of operation (days/yr) = 365 (14)
Operator labor rate ($/hr) = 24.26 (14)
Maintenance labor rate ($/hr) = 36.48 (14)

(k) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (15).

(l) Annual electricity cost ($) = (electricity rate [$/kWh]) x (total power requirement [kWh]) x (annual hours of operation [hrs/yr])

Electricity rate ($/kWh) = 0.079 (14)
Annual hours of operation (hrs/yr) = 8,760 (14)

(m) Annual compressed air cost ($) = (compressed air rate [$/Mscf]) x (Mscf/1,000 scf) x (exhaust flowrate [acfm]) x (60 min/hr) x (annual hours of operation [hrs/yr])

Compressed air rate ($/Mscf) = 0.0039 (14)
Annual hours of operation (hrs/yr) = 8,760 (14)

(n) Annual landfill cost ($) = (landfill disposal rate [$/ton]) x (pollutant removed by control device [tons/yr])

Landfill disposal rate ($/ton) = 60.0 (14)

(o) Total indirect annual cost ($) = (0.60) x ([operator labor cost ($)] + [supervisor labor cost ($)] + [maintenance labor cost ($)] + [maintenance material cost ($)]) + (0.04) x (total capital investment [$]) + (capital recovery cost [$]); see reference (15).

(p) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(q) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.
(3) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-025) for baghouse (fabric filter), pulse-jet cleaned type issued July 15, 2003. Assumes minimum typical new equipment design efficiency.
(4) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. In the quote, costs and equipment requirements for three differently sized baghouses (5,000 cfm, 20,000 cfm, and 50,000 cfm) are presented. For the smallest exhaust flowrate above (MC4), these quoted data was scaled using a ratio. All other costs/data were scaled and obtained using trendline formulas. It is important to note that the quoted costs do not include the costs associated with taxes, installation of equipment, all concrete work (including excavation, engineering, plumbing, electrical construction), building/foundation upgrades, and permitting or licensing. The cost for an add-on spark detection/extinguishment system is included due to concerns about combustible wood dust.
(5) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See Table 1.9 "Capital Cost Factors for Fabric Filters." The 1.18 factor includes instrumentation, sales tax, and freight.
(6) Information provided by Swanson Group Mfg. LLC. The site preparation cost only accounts for concrete foundation work (approximately $600 per cubic yard and an estimated pad size of 15-ft by 15-ft by 1-ft deep) ,and obtaining a professional engineer stamp. The pad size estimate does not represent an engineering design value and requires further analysis.
(7) Conservatively assumes no costs associated with site preparation or building requirements.
(8) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(9) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(10) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(11) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.2.
(12) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. Typical bag filter life is 4 years.
(13) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.1.4.
(14) See Table 3-1, Utility and Labor Rates.
(15) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.

Table 4-3
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Swanson Group Mfg. LLC—Glendale, Oregon

Process Unit ID	Emissions Unit Description	Input Parameters: Exhaust Flowrate (1) (acfm)	Input Parameters: Exhaust Flowrate (1) (scfm)	Input Parameters: PM$_{10}$ Annual Emissions Estimate (2) (tons/yr)	Pollutant Removed by Control Device (tons/yr)	Operating Parameter: System Pressure Drop (inch w.c.)	Operating Parameter: Total Collection Plate Area Estimate (ft^2)	Operating Parameter: ESP Inlet Grain Loading (gr/ft^3)
CY5	Trim Saws Cyclone #5	11,500	10,927	25.8	25.6	6.00	4,371	0.060
CY4	T&G Saw Cyclone #4	11,500	10,927	14.2	14.1	6.00	4,371	0.033
CY3	Veneer Saw Cyclone #3	15,000	14,253	6.0	5.91	6.00	5,701	0.011
TB3	Target Box #3	2,300	2,185	3.4	3.39	6.00	874	0.040
--	Sanderdust Pneumatic Conveyer	1,200	1,140	3.1	3.096	6.00	456	0.069

Process Unit ID	Emissions Unit Description	Direct Costs: Purchased Equipment Cost: Basic Equip./Services Cost	Direct Costs: Purchased Equipment Cost: Total	Direct Costs: Total Direct Cost	Total Indirect Costs	Total Capital Investment	Capital Recovery Cost of Control Device	Direct Annual Costs: Operating Labor: Operator Cost	Direct Annual Costs: Operating Labor: Supervisor Cost	Direct Annual Costs: Operating Labor: Coordinator Cost	Direct Annual Costs: Maintenance: Labor Cost	Direct Annual Costs: Maintenance: Material Cost	Direct Annual Costs: Utilities: Fan Electricity Cost	Direct Annual Costs: Utilities: Oper. Electricity Cost	Direct Annual Costs: Utilities: Compressed Air Cost	Direct Annual Costs: Utilities: Landfill Cost	Direct Annual Costs: Total Direct Annual Costs (14)	Total Indirect Annual Costs	Total Annual Cost	Annual Cost Effectiveness
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC$_p$	--	--	--	--	--	--	--	--	--	DAC	IAC	TAC	($/ton)
CY5	Trim Saws Cyclone #5	$573,294	$676,487	$1,157,511	$385,597	$1,543,108	$121,212	$53,129	$7,969	$17,710	$6,416	$6,765	$8,632	$5,861	$23,569	$1,551	$131,602	$238,130	$369,731	$14,459
CY4	T&G Saw Cyclone #4	$573,294	$676,487	$1,157,511	$385,597	$1,543,108	$121,212	$53,129	$7,969	$17,710	$6,416	$6,765	$8,632	$5,861	$23,569	$854	$130,904	$238,130	$369,034	$26,214
CY3	Veneer Saw Cyclone #3	$594,367	$701,353	$1,199,037	$399,771	$1,598,809	$125,587	$53,129	$7,969	$17,710	$6,416	$7,014	$11,259	$7,644	$30,742	$359	$142,241	$244,882	$387,123	$65,500
TB3	Target Box #3	$517,902	$611,124	$1,048,355	$348,341	$1,396,695	$109,711	$53,129	$7,969	$17,710	$6,416	$6,111	$1,726	$1,172	$4,714	$206	$99,153	$220,380	$319,533	$94,268
--	Sanderdust Pneumatic Conveyer	$511,279	$603,309	$1,035,303	$343,886	$1,379,189	$108,336	$53,129	$7,969	$17,710	$6,416	$6,033	$901	$612	$2,459	$188	$95,417	$218,258	$313,675	$101,309

See notes and formulas on following page.

Table 4-3 (Continued)
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Swanson Group Mfg. LLC—Glendale, Oregon

NOTES:

(a) Pollutant removed by control device (tons/yr) = (PM_{10} annual emissions estimate [tons/yr]) x (control efficiency [%] / 100)

Control efficiency (%) = 99.0 (3)

(b) Total collection plate area estimate (ft^2) = (average specific collection area [ft^2/1,000 scfm]) x (exhaust flowrate [scfm])

Average specific collection area (ft^2/1,000 scfm) = 400 (3)

(c) ESP inlet grain loading (gr/ft^3) = (PM_{10} annual emissions estimate [tons/yr]) x (2,000 lb/ton) x (7,000 gr/lb) / (exhaust flowrate [acfm]) x (hr/60 min) / (annual hours of operation [hrs/yr])

Annual hours of operation (hrs/yr) = 8,760 (6)

(d) Total purchased equipment cost ($) = (1.18) x (basic equipment/services cost [$]); see reference (7).

(e) Total direct cost ($) = (1.67) x (total purchased equipment cost [$]) + (site preparation cost, SP [$]) + (building cost, Bldg. [$]); see reference (7).

Site preparation cost, SP ($) = 27,778 (8)

Building cost, Bldg. ($) = 0 (9)

(f) Total indirect cost ($) = (0.57) x (total purchased equipment cost [$]); see reference (7).

(g) Total capital investment ($) = (total direct cost [$]) + (total indirect cost [$]); see reference (7).

(h) Capital recovery cost of control device($) = (total capital investment [$]) x (control device capital recovery factor); see reference (10).

Control device capital recovery factor = 0.0786 (i)

(i) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate (%) / 100]^[economic life (yrs)]) / ([1 + (interest rate [%] / 100)]^[economic life (yrs)] - 1); see reference (11).

Interest rate (%) = 4.75 (12)

Dry ESP economic life (yr) = 20 (13)

(j) Operator labor cost ($) = (operator hours per shift [hrs/shift]) x (operating shifts per day [shifts/day]) x (annual days of operation [days/yr]) x (operator labor rate [$/hr])

Operator labor rate ($/hr) = 24.26 (6)

Operating labor hours per shift (hrs/shift) = 2 (6)

Shifts per day (shifts/day) = 3 (6)

Annual days of operation (days/yr) = 365 (6)

(k) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (14).

(l) Coordinator labor cost ($) = (1/3) x (operator labor cost [$]); see reference (14).

(m) Maintenance labor cost ($-1999) = (maintenance labor cost [$-1999]) / (1999 annual chemical engineering plant cost index) x (2019 annual chemical engineering plant cost index)

Maintenance labor cost ($-1999) 4,125 (14)

1999 annual chemical engineering plant cost index = 390.6 (15)

2019 annual chemical engineering plant cost index = 607.5 (15)

(n) Maintenance material cost ($) = (0.01) x (total purchased equipment cost [$]); see reference (14).

(o) Annual fan electricity cost ($) = (0.000181) x (exhaust flowrate [acfm]) x (system pressure drop [inch w.c.]) x (annual hours of operation [hrs/yr]) x (electicity rate [$/kWh])

Annual hours of operation (hrs/yr) = 8,760 (6)

Electricity rate ($/kWh) = 0.079 (6)

(p) Annual operating power electricity cost ($) = (1.94E-03) x (total collection plate area estimate [ft^2]) x (annual hours of operation [hrs/yr]) x (electicity rate [$/kWh])

Annual hours of operation (hrs/yr) = 8,760 (6)

Electricity rate ($/kWh) = 0.079 (6)

(q) Annual compressed air cost ($) = (compressed air rate [$/Mscf]) x (Mscf/1,000 scf) x (exhaust flowrate [acfm]) x (60 min/hr) x (annual hours of operation [hrs/yr])

Compressed air rate ($/Mscf) = 0.0039 (6)

Annual hours of operation (hrs/yr) = 8,760 (6)

(r) Annual landfill cost ($) = (4.29E-06) x (ESP inlet grain loading [gr/ft^3]) x (annual hours of operation [hrs/yr]) x (exhaust flowrate [acfm]) x (landfill disposal rate [$/ton]); see reference (14).

Annual hours of operation (hrs/yr) = 8,760 (6)

Landfill disposal rate ($/ton) = 60.0 (6)

(s) Total indirect annual cost ($) = (0.60) x ([operator labor cost ($)] + [supervisor labor cost ($)] + [maintenance labor cost ($)] + [maintenance material cost ($)]) + (0.04) x (total capital investment [$]) + (capital recovery cost [$]); see reference (14).

(t) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(u) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.

(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.

(3) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-028) for dry electrostatic precipitator, wire-plate type issued July 15, 2003. Assumes the typical collection area and minimum new equipment design control efficiency.

(4) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See section 3.2.3. Assumes the average system (including ductwork and collection system) pressure drop of range provided.

(5) PPC Industries Quotation no. 18048/18049 (Revision 0) dated September 12 and 13, 2018. MFA obtained two separate costs and equipment requirements for dry ESPs sized at 21,000 acfm and 51,000 acfm. For the smallest exhaust flowrate above (MC4), the quoted data was scaled using a ratio. All other costs/data were scaled and obtained using trendline formulas. It is important to note that the quoted costs do not include the costs associated with taxes, freight, mechanical construction, electrical work, excavation, building/foundation upgrades, and permitting or licensing. The cost for an add-on spark detection/extinguishment system is included due to concerns about combustible wood dust.

(6) See Table 3-1, Utility and Labor Rates.

(7) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.16 "Capital Cost Factors for ESPs."

(8) Information provided by Swanson Group Mfg. LLC. The site preparation cost only accounts for concrete foundation work (approximately $600 per cubic yard and an estimated pad size of 20-ft by 20-ft by 2-ft deep) ,and obtaining a professional engineer stamp. The pad size estimate does not represent an engineering design value and requires further analysis.

(9) Conservatively assumes no costs associated with site preparation or building requirements.

(10) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.

(11) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.

(12) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.

(13) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See section 3.4.2.

(14) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.21.

(15) See Chemical Engineering magazine, chemical engineering plant cost index section for annual indices.

Table 5-1
Cost Effectiveness Derivation for Selective Non-Catalytic Reducer Installation
Swanson Group Mfg. LLC—Glendale, Oregon

Emissions Unit ID	Emissions Unit Description	Input Parameters				Pollutant Removed by Control Device		Normalized Stoichiometric Ratio (e)	Operating Parameters				
		Heat Input Capacity (1) (MMBtu/hr)	Uncontrolled NO$_x$ Emissions Estimate		Uncontrolled NO$_x$ Emissions in Flue Gas (b) (lb/MMBtu)				Reagent Mass Consumption (f) (lb/hr)	Reagent Solution Flowrate (g) (gal/hr)	Power Demand (h) (kW)	Water Demand (i) (gal/hr)	Additional Fuel Usage (j) (MMBtu/hr)
			Hourly (a) (lb/hr)	Annual (3) (tons/yr)		Hourly (c) (lb/hr)	Annual (d) (tons/yr)						
USEPA COST MANUAL VARIABLE		Q_B	--	--	$NO_{x_{in}}$	--	--	NSR	$m_{reagent}$	q_{sol}	P	q_{water}	ΔFuel
1PH	Hogged Fuel Boiler	125	16.3	71.2	0.13	4.06	17.8	1.85	19.6	4.13	36.4	18.8	0.16

Emissions Unit ID	Emissions Unit Description	Direct Cost	Indirect Cost	Total Capital Investment (m)	Capital Recovery Cost of Control Device (n)	Direct Annual Costs							Total Indirect Annual Costs (w)	Total Annual Cost (x)	Annual Cost Effectiveness (y)
								Utilities							
		Capital Cost (k)	Balance of Plant Cost (l)			Maintenance Labor and Material Cost (p)	Reagent Usage (q)	Electricity Cost (s)	Water Usage Cost (t)	Fuel Additive Cost (u)	Ash Disposal Cost (v)	Total Direct Annual Costs (27)			
USEPA COST MANUAL VARIABLE		$SNCR_{cost}$	BOP_{cost}	TCI	CR	--	--	--	--	--	--	DAC	IDAC	TAC	($/ton)
1PH	Hogged Fuel Boiler	$330,501	$579,996	$1,308,522	$102,785	$19,628	$67,290	$25,165	$754	$1,987	$83.46	$114,907	$103,374	$218,281	$12,265

NOTES:

(a) Uncontrolled hourly NO$_x$ emissions estimate (lb/hr) = (uncontrolled annual NO$_x$ emissions estimate [tons/yr]) x (2,000 lb/ton) / (annual hours of operation [hrs/yr])

Annual hours of operation (hrs/yr) = 8,760 (2)

(b) Uncontrolled NO$_x$ emissions in flue gas (lb/MMBtu) = (uncontrolled hourly NO$_x$ emissions estimate [lb/hr]) / (heat input capacity [MMBtu/hr])

(c) Hourly pollutant removed by control device (lb/hr) = (uncontrolled hourly NO$_x$ emissions estimate [lb/hr]) x (control efficiency [%] / 100)

Control efficiency (%) = 25.0 (4)

(d) Annual pollutant removed by control device (tons/yr) = (uncontrolled annual NO$_x$ emissions estimate [tons/yr]) x (control efficiency [%] / 100)

Control efficiency (%) = 25.0 (4)

(e) Normalized stoichiometric ratio = ([2] x [uncontrolled NOX emissions in flue gas (lb/MMBtu)] + [0.7]) x (control efficiency [%] / 100) / (uncontrolled NOX emissions in flue gas [lb/MMBtu]); see reference (5).

Control efficiency (%) = 25.0 (4)

(f) Reagent mass consumption (lb/hr) = (uncontrolled NOX emissions in flue gas [lb/MMBtu]) x (heat input capacity [MMBtu/hr]) x (normalized stoichiometric ratio) x (60.06 lb-urea/lb-mole) / (46.01 lb-NO$_2$/lb-mole) / (theoretical stoichiometric ratio]); see reference (6).

Theoretical stoichiometric ratio = 2 (7)

(g) Reagent solution flowrate (gal/hr) = (reagent mass consumption [lb/hr]) / (aqueous reagent solution concentration [%] / 100) / (aqueous reagent solution density [lb/ft³]) x (7.4805 gal/ft³); see reference (8).

Aqueous reagent solution concentration (%) = 50.0 (8)

Aqueous reagent solution density (lb/ft³) = 71.0 (8)

(h) Power demand (kW) = (0.47) x (uncontrolled NOX emissions in flue gas [lb/MMBtu]) x (normalized stoichiometric ratio) x (heat input capacity [MMBtu/hr]) / (net plant heat rate [MMBtu/MWh]) + (power required to heat tank [kW]); see reference (9).

Net plant heat rate (MMBtu/MWh) = 10.0 (10)

Power required to heat tank (kW) = 35.0 (11)

(i) Water demand (gal/hr) = (4) x (reagent mass consumption [lb/hr]) / (aqueous reagent solution concentration [%] / 100) / (density of water [lb/gal]); see reference (12).

Aqueous reagent solution concentration (%) = 50.0 (8)

Density of water (lb/gal) = 8.345

(j) Additional fuel usage (MMBtu/hr) = (9) x (heat of vaporization of water [Btu/lb]) x (reagent mass consumption [lb/hr]) x (MMBtu/1,000,000 Btu); see reference (13).

Heat of vaporization of water (Btu/lb) = 900 (13)

(k) Capital cost ($) = (capital cost [1999 $/MMBtu/hr]) x (heat input capacity [MMBtu/hr]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 1999)

Capital cost (1999 $/MMBtu/hr) = 1,700 (4)

Chemical engineering plant cost index for 2019 = 607.5 (14)

Chemical engineering plant cost index for 1999 = 390.6 (14)

(l) Balance of plant costs ($) = (213,000) x ([heat input capacity (MMBtu/hr)] / [net plant heat rate (MMBtu/MWh)])^(0.33) x (hourly pollutant removed by control device [lb/hr])^(0.12) x (retrofit factor); see reference (15).

Net plant heat rate (MMBtu/MWh) = 10.0 (10)

Retrofit factor = 1.00 (15)

(m) Total capital investment ($) = (1.3) x ([capital cost ($)] + [balance of plant cost ($)]) + (reagent storage tank cost [$]) + (reagent storage tank construction [$]); see reference (16).

Reagent storage tank ($) = 74,875 (17)

Reagent storage area construction ($) = 50,000 (18)

(n) Capital recovery cost of control device ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (19).

Control device capital recovery factor = 0.0786 (o)

(o) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate (%) / 100]^[economic life (yrs)]) / ([1 + (interest rate [%] / 100)]^[economic life (yrs)] - 1); see reference (20).

Interest rate (%) = 4.75 (21)

SNCR economic life (yr) = 20 (22)

(p) Annual maintenance cost ($) = (0.015) x (total capital investment [$]); see reference (23).

(q) Annual reagent usage cost ($) = (reagent solution flowrate [gal/hr]) x (reagent cost [$/50% urea solution]) x (annual hours of operation [hrs/yr])

Reagent rate ($/50% urea solution) = 1.86 (r)

Annual hours of operation (hrs/yr) = 8,760 (2)

(r) Reagent rate ($/50% urea solution) = (reagent cost [2016 $/50% urea solution]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 2016)

Reagent rate (2016 $/50% urea solution) = 1.66 (4)

Chemical engineering plant cost index for 2019 = 607.5 (14)

Chemical engineering plant cost index for 2016 = 541.7 (14)

(s) Annual electricity cost ($) = (power demand [kWh]) x (electricity rate [$/kWh]) x (annual hours of operation [hrs/yr])

Electricity rate ($/kWh) = 0.079 (2)

Annual hours of operation (hrs/yr) = 8,760 (2)

(t) Annual water usage cost ($) = (water demand [gal/hr]) x (Mgal/1,000 gal) x (water rate [$/Mgal]) x (annual hours of operation [hrs/yr])

Water rate ($/Mgal) = 4.58 (2)

Annual hours of operation (hrs/yr) = 8,760 (2)

(u) Annual fuel additive cost ($) = (additional fuel usage [MMBtu/hr]) x (annual hours of operation [hrs/yr]) x (wood fuel rate [$/BDT] / (high heat value of wood [MMBtu/BDT]); see reference (24).

High heat value of wood (MMBtu/BDT) = 17.48 (25)

Wood fuel rate ($/BDT) = 25.0 (2)

Annual hours of operation (hrs/yr) = 8,760 (2)

(v) Ash disposal ($) = (additional fuel usage [MMBtu/hr]) x (ash weight percent [%] / 100) x (annual hours of operation [hrs/yr]) / (high heat value of wood [MMBtu/BDT]) x (landfill disposal rate [$/ton]); see reference (26).

Ash weight percent (%) = 1.75 (27)

Annual hours of operation (hrs/yr) = 8,760 (2)

High heat value of wood (MMBtu/BDT) = 17.48 (25)

Landfill disposal rate ($/ton) = 60.0 (2)

(w) Total indirect annual cost ($) = (0.03) x (annual maintenance cost [$]) + (capital recovery cost [$]); see reference (29).

(x) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(y) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:

(1) See Table 2-4. Emissions Unit Input Assumptions and Exhaust Parameters.

(2) See Table 3-1. Utility and Labor Rates.

(3) See Table 2-2. NO$_x$ Evaluation for Regional Haze Four Factor Analysis.

(4) USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-031) for selective non-catalytic reduction (SNCR) issued July 15, 2003. Assumes the average FM control efficiency and average capital cost.

(5) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.17.

(6) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.18.

(7) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. Assumes theoretical stoichiometric ratio for urea.

(8) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equations 1.19 and 1.20.

(9) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.42.

(10) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.3.1.

(11) Information provided by Chromalox vendor. Assumes heating of urea is required to a minimum of 95°F.

(12) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.45.

(13) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.48.

(14) See Chemical Engineering magazine. Chemical Engineering Plant Cost Index (CEPCI) for annual indices.

(15) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.37. Assumes retrofit factor.

(16) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.35.

(17) Cost representative of 12,500 gallon double-wall, heated, storage tank provided by National Tank Outlet and Chromalox. Cost includes freight charges, but excludes sales tax.

(18) Assumes engineering estimate cost of construction for a covered storage tank (e.g., including engineering design services, concrete/foundation/secondary containment area work, and structure construction).

(19) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.

(20) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.

(21) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.

(22) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.4.2.

(23) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.39.

(24) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.49.

(25) 40 CFR, Subchapter C, Part 98, Subpart C. See Table C-1 "Default CO2 Emission Factors and High Heat Values of Various Types of Fuel". Factor for wood and wood residuals.

(26) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equations 1.50 and 1.51.

(27) Assumes typical average ash weight percent from the burning of hogged fuel.

(28) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.38.

(29) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.52 and 1.53.

REGIONAL HAZE
FOUR-FACTOR ANALYSIS

WOODGRAIN MILLWORK, INC.

Prepared for

WOODGRAIN MILLWORK, INC.

LA GRANDE, OREGON

June 9, 2020

Project No. 1863.02.01

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MAUL
FOSTER
ALONGI

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LIMITATIONS

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ACRONYMS AND ABBREVIATIONS

\$/ton	dollars per ton of pollutant controlled
°F	degrees Fahrenheit
Analysis	Regional Haze Four Factor Analysis
BH	baghouse
CAA	Clean Air Act
Control Cost Manual	USEPA Air Pollution Control Cost Manual
DEQ	Oregon Department of Environmental Quality
ESP	electrostatic precipitator
facility	particleboard manufacturing facility located at 62621 Oregon Highway 82, La Grande, Oregon 97850
Federal Guidance Document	Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003
GFD	green furnish dryer
MFA	Maul Foster and Alongi, Inc.
MMBtu/hr	million British thermal units per hour
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO	nitric oxide
NO_X	oxides of nitrogen
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns or less
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
USEPA	U.S. Environmental Protection Agency
Woodgrain	Woodgrain Millwork, Inc.

1 INTRODUCTION

The Oregon Department of Environmental Quality (DEQ) is developing a State Implementation Plan (SIP) as part of the Regional Haze program in order to protect visibility in Class I areas. The SIP developed by the DEQ covers the second implementation period ending in 2028, and must be submitted to the U.S. Environmental Protection Agency (USEPA) for approval. The second implementation period focuses on making reasonable progress toward national visibility goals, and assesses progress made since the 2000 through 2004 baseline period.

In a letter dated December 23, 2019, the DEQ requested that 31 industrial facilities conduct a Regional Haze Four Factor Analysis (Analysis). The Analysis estimates the cost associated with reducing visibility-impairing pollutants including, particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), oxides of nitrogen (NO_X), and sulfur dioxide (SO_2). The four factors that must be considered when assessing the states' reasonable progress, which are codified in Section 169A(g)(1) of the Clean Air Act (CAA), are:

(1) The cost of control,

(2) The time required to achieve control,

(3) The energy and non-air-quality environmental impacts of control, and

(4) The remaining useful life of the existing source of emissions.

The DEQ has provided the following three guidance documents for facilities to reference when developing their Analysis:

(1) USEPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003 (Federal Guidance Document).

(2) USEPA Air Pollution Control Cost Manual, which is maintained online and includes separate chapters for different control devices as well as several electronic calculation spreadsheets that can be used to estimate the cost of control for several control devices (Control Cost Manual).

(3) Modeling Guidance for Demonstrating Air Quality Goals for Ozone, [particulate matter with an aerodynamic diameter of 2.5 microns or less] $PM_{2.5}$, and Regional Haze (November 2018), EPA-454/R-18-009.

The development of this Analysis has relied on these guidance documents.

1.1 Facility Description

Woodgrain Millwork, Inc. (Woodgrain) owns and operates a particleboard manufacturing facility located at 62621 Oregon Highway 82, La Grande, Oregon 97850 (the facility). The facility currently operates under Title V Operating Permit No. 31-0002-TV-01, issued by the DEQ to Boise Cascade

Wood Products, LLC, on July 30, 2014. Per Addendum No. 1 to the existing permit, facility ownership was revised from Boise Cascade Wood Products, LLC, to Woodgrain on January 11, 2019. The facility is a major stationary source of criteria and hazardous air pollutants.

The facility is located northwest of La Grande city center, just outside the extents of Island City proper. The area immediately surrounding the facility is predominantly characterized by flat terrain and agricultural land use. The nearest Class I area is the Eagle Cap Wilderness Area, approximately 25 kilometers east-southeast of the facility.

1.2 Process Description

Both green or pre-dried wood furnish is delivered by trucks and used as raw materials. The wood furnish is unloaded and pneumatically conveyed to one of three storage buildings. Green wood furnish at approximately 50 percent moisture content is dried prior to processing. Once dry, wood furnish is sent to either of the two particleboard manufacturing lines and separated into face and/or core material.

The face and core materials are then screened, refined, dried, mixed with urea-formaldehyde resins, and formed into mats. Various additives are introduced to the mat in order to meet product specifications. The mats are loaded into one of two multiplaten presses and, under heat and pressure, cured into particleboard panels. The cured panels are then cooled and stabilized prior to sanding, sizing, and final packaging. The facility produces industrial grade particleboard in thicknesses ranging from five-sixteenths to one and three-sixteenths inches.

Two boilers are used to produce steam to heat the finish dryers and presses. Sanderdust generated by the sanding operation is collected and used as fuel in the Line 2 boiler and green furnish dryer (GFD). The Line 1 boiler is fueled by natural gas-fired combustion with propane back-up. Trim from the panel sizing operation, reject material, and other wood materials are returned to the process as raw material.

2 APPLICABLE EMISSION SOURCES

Woodgrain retained Maul Foster & Alongi, Inc. (MFA) to assist the facility with completing this Analysis. Emissions rates for each visibility-impairing pollutant (PM_{10}, NO_X, and SO_2) were tabulated. These emissions rates represent a reasonable projection of actual source operation in the year 2028. As stated in the Federal Guidance Document,[1] estimates of 2028 emission rates should be used for the Analysis. It is assumed that current potential to emit (Plant Site Emission Limit) emission rates at the facility represent the most reasonable estimate of actual emissions in 2028.

After emission rates were tabulated for each emissions unit, estimated emission rates for each pollutant were sorted from the highest emission rate to the lowest. The emission units collectively contributing

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[1] See Federal Guidance Document page 17, under the heading "Use of actual emissions versus allowable emissions."

to 90 percent of the total facility emissions rate for a single pollutant were identified and selected for the Analysis.

This method of emission unit selection ensures that larger emission units are included in the Analysis. Larger emission units represent the likeliest potential for reduction in emissions that would contribute to a meaningful improvement in visibility at federal Class I areas. It would not be reasonable to assess many small emission units—neither on an individual basis (large reductions for a small source likely would not improve visibility and would not be cost effective), nor on a collective basis (the aggregate emission rate would be no greater than 10 percent of the overall facility emissions rate, and thus not as likely to improve visibility at federal Class I areas, based solely on the relatively small potential overall emission decreases from the facility).

The following sections present the source selection, associated emission rates that will be used in the Analysis, and pertinent source configuration and exhaust parameters.

2.1 Sources of PM_{10} Emissions

A summary of the selected emission units and associated PM_{10} emission rates included in the Analysis is presented in Table 2-1 (attached). A detailed description of each emissions unit is presented below. The permit emission unit ID is shown in parentheses.

2.1.1 Line 1 and 2 Boilers (B1 and B2)

The Line 1 boiler is a Babcock and Wilcox natural gas-fired package boiler, with propane backup. The Line 1 boiler has a maximum rated heat input capacity of 56 million British thermal units per hour (MMBtu/hr). Exhaust from the Line 1 boiler is used to supplement heating in the Line 1 core dryer or is vented directly to the atmosphere.

The Line 2 boiler is also a Babcock and Wilcox industrial watertube type "D" boiler, fueled primarily by sanderdust with concurrent natural gas usage and propane as backup. The sanderdust is pneumatically conveyed directly into the boiler combustion chamber as fuel. Its maximum rated heat input capacity is 80 MMBtu/hr. Exhaust from the Line 2 boiler is routed to a dry electrostatic precipitator (ESP) for control of fine particulate emissions prior to emitting to the atmosphere

The Line 1 and 2 boilers are subject to, and required to comply with, the National Emission Standard for Hazardous Air Pollutants (NESHAP) for Major Source Industrial, Commercial, and Institutional Boilers and Process Heaters, codified at Title 40 Code of Federal Regulations Part 63 Subpart DDDDD, as introduced under section 112(g) of the CAA, effective November 20, 2015. Based on USEPA guidance[2] provided to states for the Second Implementation Period, the USEPA believes it is reasonable for states to exclude an emissions unit for further analysis if:

> For the purpose of [particulate matter (PM)] control measures, a unit that is subject to and complying with any CAA section 112 [NESHAP] or CAA section 129 solid waste combustion rule, promulgated

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[2] USEPA Office of Air Quality Planning and Standards, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period." August 2019.

> or reviewed since July 31, 2013, that uses total or filterable PM as a surrogate for metals or has specific emission limits for metals. The NESHAPs are reviewed every 8 years and their emission limits for PM and metals reflects at least the maximum achievable control technology for major sources and the generally available control technology for area sources. It is unlikely that an analysis of control measures for a source meeting one of these NESHAPs would conclude that even more stringent control of PM is necessary to make reasonable progress.

Based on the USEPA guidance, both boilers were excluded from further evaluation in the PM_{10} Analysis.

2.1.2 Green Furnish Dryer (GFD/C46)

The GFD is utilized to dry green wood furnish delivered to the facility prior to processing. The GFD is primarily fueled by sanderdust and a natural gas pilot light and has a maximum rated drying capacity of 67,000 bone-dry tons per year. Sanderdust is routed to the GFD through the GFD sanderdust feed bin, discussed in more detail in Section 2.1.6.

Dried furnish is routed with the dryer exhaust stream to two downstream cyclones for transfer to processing. The exhaust of each cyclone is combined and routed to a wet ESP for control of fine particulate emissions, followed by a regenerative thermal oxidizer for control of volatile organic compound emissions. The wet ESP was installed in 1997, and the regenerative thermal oxidizer was installed in 2003.

The GFD emissions unit is already equipped with state-of-the-art pollution control technology to control emissions of PM_{10}. As a result, the GFD emissions unit was excluded from further evaluation in the PM_{10} Analysis.

2.1.3 Line 1 and Line 2 Presses (P1 and P2)

The Line 1 and Line 2 presses are hydraulically driven and heated by steam generated by the Line 1 and 2 boilers. The presses apply heat and pressure to activate the urea-formaldehyde resin and bond the wood fibers into a solid panel. The typical operating temperature range of either press is between 305 degrees Fahrenheit (°F) and 330°F. There are four roof vents on the Line 1 press and five on the Line 2 press. The Line 1 press was installed in 1965, and the Line 2 press was installed in 1969. Exhaust from each press vent is combined and routed to the regenerative catalytic oxidizer for control of volatile organic compound emissions.

2.1.4 Transfer to Line 1 Storage (C4)

Emissions unit MS represents a collection of material storage cyclone process units. The transfer to Line 1 storage cyclone process unit is designated within the MS emissions unit grouping. Reject from the reman area and trim material from the Line 1 Jenkins saw are pneumatically conveyed to the Line 1 storage area. Cyclone C4 is used to separate the reject and trim material, via centrifugal forces, from the exhaust stream for collection and reuse. The exhaust stream exiting the top of cyclone C4 is emitted to the atmosphere uncontrolled.

2.1.5 Line 1 Reject Bin (C23)

Emissions unit BF represents a collection of blending and forming cyclone process units. The Line 1 reject bin cyclone process unit is designated within the BF emissions unit grouping. Line 1 former, tipple, mat trim, and unloader rejected material is pneumatically conveyed to the Line 1 reject bin. Cyclone C23 is used to separate the reject material, via centrifugal forces, from the exhaust stream for collection and reuse. The exhaust stream exiting the top of cyclone C23 is emitted to the atmosphere uncontrolled.

2.1.6 Green Furnish Dryer Sanderdust Feed Bin (C47)

Stored sanderdust is pneumatically conveyed to the GFD sanderdust feed bin. Cyclone C47 is used to separate the sanderdust, via centrifugal forces, from the exhaust stream. Sanderdust dropping out of the cyclone is delivered to the GFD for drying. The exhaust stream exiting the top of cyclone C47 is routed to baghouse (BH) no. 21 for control of fine particulate emissions. The GFD sanderdust feed bin cyclone was installed in 1996.

2.1.7 Line 1 and Line 2 Board Coolers (BC1 and BC2)

Cured particleboard panels are cooled by the Line 1 and Line 2 board coolers after exiting the presses. Prior to stacking, cooled particleboard panels are sent to the finishing area for sanding and trimming to final product dimensions. There are four roof vents on the Line 1 board cooler and four vents on the Line 2 board cooler. Process exhaust from the Line 1 and 2 board coolers is routed through each applicable vent and emitted to the atmosphere uncontrolled.

2.1.8 Natural Gas in the Line 1 and 2 Dryers

There are two rotary dryers located on Line 1. The HEIL rotary core dryer (i.e., dedicated to drying furnish for the particleboard core) is heated by natural gas-fired combustion and supplemental flue gas from the Line 1 boiler. The HEIL rotary face dryer (i.e., dedicated to drying furnish for the particleboard face) is heated by natural gas-fired combustion and steam. The Line 1 dryers can dry furnish up to 115,200,000 square feet of furnish on a three-quarter-inch basis per year, and the maximum rated heat input capacity is approximately 3.5 MMBtu/yr.

Dried furnish leaving the Line 1 rotary core and face dryers is pneumatically conveyed to cyclone C9 and cyclone C10 for furnish removal and control of coarse particulate emissions, respectively. Process exhausts from cyclones C9 and C10 are routed to baghouses BH25 and BH26, respectively, for further control of fine particulate emissions.

There are also two rotary dryers located on Line 2. Both the MEC rotary core dryer and MEC rotary face dryer are heated by natural gas-fired combustion and steam. The Line 2 dryers can dry furnish up to 124,800,000 square feet of furnish on a three-quarter-inch basis per year, and the maximum rated heat input capacity is approximately 4.25 MMBtu/yr.

Similar to the Line 1 dryers, dried furnish leaving the Line 2 rotary core and face dryers is pneumatically conveyed to cyclones C14 and C15 for furnish removal and control of coarse particulate emissions, respectively. Process exhausts from cyclones C14 and C15 are routed to baghouses BH28 and BH29, respectively, for further control of fine particulate emissions.

Only the emissions associated with natural gas-fired combustion in the dryers contribute to 90 percent to the total facility PM_{10} emissions rate (see emissions ranking process described in Section 2). As a result, only the emissions associated natural gas-fired combustion in each dryer are included for further evaluation in the Analysis.

2.2 Sources of NO_X Emissions

A summary of the selected emission units and associated NO_X emission rates to be evaluated in the Analysis are presented in Table 2-2 (attached). As shown in the table, only the Line 2 boiler and GFD are included for further evaluation in the NO_X Analysis. All other emission units fall below the threshold of 90 percent contribution to the total facility NO_X emissions rate.

2.3 Sources of SO_2 Emissions

A summary of the selected emission units and associated SO_2 emission rates to be evaluated in the Analysis are presented in Table 2-3 (attached). As shown in the table, only the Line 1 boiler, Line 2 boiler, and GFD are included for further evaluation in the SO_2 Analysis. All other emission units fall below the threshold of 90 percent contribution to the total facility SO_2 emissions rate.

2.4 Emission Unit Exhaust Parameters

A summary of the emissions unit exhaust parameters included in the Analysis is presented in Table 2-4 (attached). Emission units identified in the preceding sections as infeasible for control, as already equipped with state-of-the-art control, or otherwise exempt are not presented. These emissions units will not be evaluated further in this Analysis.

3 REGIONAL HAZE FOUR-FACTOR ANALYSIS METHODOLOGY

This Analysis has been conducted consistent with the Federal Guidance Document, which outlines six steps to be taken when addressing the four statutorily required factors included in the Analysis. These steps are described in the following sections.

3.1 Step 1: Determine Emission Control Measures to Consider

Identification of technically feasible control measures for visibility-impairing pollutants is the first step in the Analysis. While there is no regulatory requirement to consider all technically feasible measures, or any specific controls, a reasonable set of measures must be selected. This can be accomplished by identifying a range of options, which could include add-on controls, work practices that lead to emissions reductions, operating restrictions, or upgrades to less efficient controls, to name a few.

3.2 Step 2: Selection of Emissions

Section 2 details the method for determining the emission units and emission rates to be used in the Analysis. Potential to emit emission rates were obtained from the existing permit review report. These emissions rates represent a reasonable projection of actual source operation in the year 2028.

3.3 Step 3: Characterizing Cost of Compliance (Statutory Factor 1)

Once the sources, emissions, and control methods have all been selected, the cost of compliance is estimated. The cost of compliance, expressed in units of dollars per ton of pollutant controlled ($/ton), describes the cost associated with the reduction of visibility-impairing pollutants. Specific costs associated with operation, maintenance, and utilities at the facility are presented in Table 3-1 (attached).

The Federal Guidance Document recommends that cost estimates follow the methods and recommendations in the Control Cost Manual. This includes the recently updated calculation spreadsheets that implement the revised chapters of the Control Cost Manual. The Federal Guidance Document recommends using the generic cost estimation algorithms detailed in the Control Cost Manual in cases where site-specific cost estimates are not available.

Additionally, the Federal Guidance Document recommends using the Control Cost Manual in order to effect an "apples-to-apples" comparison of costs across different sources and industries.

3.4 Step 4: Characterizing Time Necessary for Compliance (Statutory Factor 2)

Characterizing the time necessary for compliance requires an understanding of construction timelines, which include planning, construction, shake-down and, finally, operation. The time that is needed to complete these tasks must be reasonable, and does not have to be "as expeditiously as practicable…" as is required by the Best Available Retrofit Technology regulations.

3.5 Step 5: Characterizing Energy and Non-air Environmental Impacts (Statutory Factor 3)

Both the energy impacts and the non-air environmental impacts are estimated for the control measures that were costed in Step 3. These include estimating the energy required for a given control method, but do not include the indirect impacts of a particular control method, as stated in the Federal Guidance Document.

The non-air environmental impacts can include estimates of waste generated from a control measure and its disposal. For example, nearby water bodies could be impacted by the disposed-of waste, constituting a non-air environmental impact.

3.6 Step 6: Characterize the Remaining Useful Life of Source (Statutory Factor 4)

The Federal Guidance Document highlights several factors to consider when characterizing the remaining useful life of the source. The primary issue is that often the useful life of the control measure is shorter than the remaining useful life of the source. However, it is also possible that a source is slated to be shut down well before a control device would be cost effective.

4 PM_{10} ANALYSIS

The Analysis for PM_{10} emissions follows the six steps previously described in Section 3.

4.1 Step 1—Determine PM_{10} Control Measures for Consideration

4.1.1 Baghouses

BHs, or fabric filters, are common in the wood products industry. In a fabric filter, flue gas is passed through a tightly woven or felted fabric, causing PM in the flue gas to collect on the fabric by sieving and other mechanisms. Fabric filters may be in the form of sheets, cartridges, or bags, with a number of the individual fabric filter units housed together in a group. Bags are one of the most common forms of fabric filter. The dust cake that forms on the filter from the collected PM can significantly increase collection efficiency. The accumulated particles are periodically removed from the filter surface by a variety of mechanisms and are collected in a hopper for final disposition.

Typical new equipment design efficiencies are between 99 and 99.9 percent. Several factors determine fabric filter collection efficiency. These include gas filtration velocity, particle characteristics, fabric characteristics, and the cleaning mechanism. In general, collection efficiency increases with decreasing filtration velocity and increasing particle size. Fabric filters are generally less expensive than ESPs, and they do not require complicated control systems. However, fabric filters are subject to plugging for certain exhaust streams and do require maintenance and inspection to ensure that plugging or holes in the fabric have not developed. Regular replacement of the filters is required, resulting in higher maintenance and operating costs.

Certain process limitations can affect the operation of BHs in some applications. For example, exhaust streams with very high temperatures (i.e., greater than 500°F) may require specially formulated filter materials and/or render BH control infeasible. Additional challenges include the particle characteristics, such as materials that are "sticky" and tend to impede the removal of material from the filter surface. Exhaust gases that exhibit corrosive characteristics may also impose limitations on the effectiveness of BHs. In wood products applications it is expected that particle characteristics, specifically particle and exhaust moisture content, may limit the feasibility on implementation. However, for some sources, baghouses are considered technically feasible.

4.1.2 Wet Venturi Scrubbers

Wet scrubbers remove particulate from gas streams primarily by inertial impaction of the particulate onto a water droplet. In a venturi scrubber, the gas is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity, causing the water to shear into fine droplets. Particles in the gas stream then impact the water droplets. The entrained water droplets are subsequently removed from the gas stream by a cyclonic separator. Venturi scrubber control efficiency increases with increasing pressure drops for a given particle size. Control efficiency increases with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Control efficiencies are typically around 90 percent for particles with a diameter of 2.5 microns or larger.

It is important to note that although wet scrubbers mitigate air pollution concerns, they also generate a water pollution concern. The effluent wastewater and wet sludge stream created by wet scrubbers requires that the operating facility have a water treatment system and subsequent disposal system in place. These consequential systems increase the overall cost of wet scrubbers and cause important environmental impacts to consider.

As wet scrubbers become saturated with a pollutant it is necessary to discharge (blowdown) some scrubber liquid and add fresh water. A water treatment system of suitable size is necessary to handle the scrubber blowdown. The facility is not connected to a city sewer system. The facility is reliant on a closed-loop system via the process wastewater treatment pond. The amount of scrubber blowdown that would be created for an appropriately sized wet scrubber would likely overwhelm the existing system, but it is currently unknown. The facility reserves the right to re-evaluate the technical feasibility of implementing a wet venturi scrubber at the facility should the DEQ request clarification.

4.1.3 Electrostatic Precipitator

ESPs are used extensively for control of PM emissions. An ESP is a particulate control device that uses electrical force to move particles entrained with a gas stream onto collection surfaces. An electrical charge is imparted on the entrained particles as they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the corona that charges the particles, thereby allowing for their collection on the oppositely-charged collector walls. In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. Instead of the collection hoppers used by dry ESPs, wet ESPs utilize a drainage system and water treatment of some sort. In dry ESPs, the collectors are knocked, or “rapped,” by various mechanical means to dislodge the collected particles, which slide downward into a hopper for collection.

Typical control efficiencies for new installations are between 99 and 99.9 percent. Older existing equipment has a range of actual operating efficiencies of 90 to 99.9 percent. While several factors determine ESP control efficiency, ESP size is the most important because it determines exhaust residence time; the longer a particle spends in the ESP, the greater the chance of collecting it. Maximizing electric field strength will maximize ESP control efficiency. Control efficiency is also affected to some extent by particle resistivity, gas temperature, chemical composition (of the particle and gas), and particle size distribution.

Similar to wet scrubber control systems, wet ESPs also create a water pollution concern as they reduce air pollution. Use of wet ESPs generates a wastewater and wet sludge effluent that requires treatment and subsequent disposal, thereby increasing the overall costs. Given the significant cost of compliance presented in Table 4-1 for dry ESP installations, the cost analyses for wet ESP were not completed (as they will be even higher).

4.2 Step 2—Selection of Emissions

See Sections 2.1 for descriptions of the PM_{10} emission units and emission rates selected for the Analysis.

4.3 Step 3—Characterizing Cost of Compliance

Tables 4-2 through 4-5 present the detailed cost analyses of the technically feasible PM_{10} control technologies included in the Analysis. Note the natural gas in the Line 1 and 2 dryer is already controlled by the baghouses and therefore, was not included in Table 4-2 (e.g., baghouse cost effectiveness derivation table). A summary of the cost of compliance, expressed in $/ton, is shown below in Table 4-1:

Table 4-1
Cost of Compliance for PM_{10}

Emissions Unit	Emissions Unit ID	Cost of Compliance ($/ton)		
		BH	Dry ESP	Wet Venturi Scrubber
Line 1 and Line 2 Press Vents	P1 & P2	$51,879	$70,559	$58,502
Transfer to Line 1 Storage	C4	$117,824	$146,114	$134,116
Line 1 Reject Bin	C23	$175,824	$217,349	$199,395
GFD Sanderdust Feed Bin	C47	$308,815	$389,991	$351,189
Line 2 Board Cooler	BC2	$489,913	$653,159	$568,770
Line 1 Board Cooler	BC1	$433,511	$549,699	$495,053
Natural Gas in Line 2 Dryer	--	--	$3,745,701	$3,115,161
Natural Gas in Line 1 Dryer	--	--	$4,181,572	$3,511,844

4.4 Step 4—Characterizing Time Necessary for Compliance

Several steps will be required before the control device is installed and fully operational. After selection of a control technology, all of the following will be required: permitting, equipment procurement, construction, startup and a reasonable shakedown period, and verification testing. It is anticipated that it will take up to 18 months to achieve compliance.

4.5 Step 5—Characterizing Energy and Non-air Environmental Impacts

4.5.1 Energy Impacts

Energy impacts can include electricity and/or supplemental fuel used by a control device. Electricity use can be substantial for large projects if the control device uses large fans, pumps, or motors. BH control systems require significant electricity use to operate the powerful fans required to overcome the pressure drop across the filter bags. Dry ESPs are expected to require even more electricity than a BH, since high-voltage electricity is required for particle collection and removal. Dry ESPs also require powerful fans to maintain exhaust flow through the system. Similarly, wet venturi scrubbers and wet ESPs will use significant amounts of electricity to power large pumps used to supply water for the control device and the subsequent treatment process.

4.5.2 Environmental Impacts

Expected environmental impacts for BHs and dry ESPs include the management of materials collected by the control devices. For sources where this material is clean wood residuals, it may be possible to reuse the material in the production process. However, collected materials that are degraded or that contain potential contaminants would be considered waste materials requiring disposal at a landfill.

As mentioned above, wet venturi scrubbers and wet ESPs generate liquid waste streams, creating a water pollution issue. The effluent of wastewater and wet sludge generated by both control technologies will require the facility to have in place an appropriately sized water treatment system and subsequent waste disposal system and/or procedure. These systems increase the overall cost of installation and cause important environmental impacts to consider.

While none of the control technologies evaluated in the PM_{10} Analysis would require the direct consumption of fossil fuels, another, less quantifiable, impact from energy use may result from producing the electricity (i.e., increased greenhouse gases and other pollutant emissions). In addition, where fossil fuels are used for electricity production, additional impacts are incurred from the mining/drilling and use of fossil fuels for combustion.

4.6 Step 6—Characterize the Remaining Useful Life

It is anticipated that the remaining life of the emissions units, as outlined in the Analysis, will be longer than the useful life of the technically feasible control systems. No emissions units are subject to an enforceable requirement to cease operation. Therefore, in accordance with the Federal Guidance Document, the presumption is that the control system would be replaced by a like system at the end of its useful life. Thus, annualized costs in the Analysis are based on the useful life of the control system rather than the useful life of the emissions units.

5 NO$_X$ ANALYSIS

The Analysis for NO$_X$ emissions follows the six steps previously described in Section 3.

5.1 Step 1—Determine NO$_X$ Control Measures for Consideration

5.1.1 Selective Non-catalytic Reduction

Selective non-catalytic reduction (SNCR) systems have been widely employed for biomass combustion systems. SNCR is relatively simple because it utilizes the combustion chamber as the control device reactor, achieving control efficiencies of 25 to 70 percent. SNCR systems rely on the reaction of ammonia and nitric oxide (NO) at temperatures of 1,550 to 1,950°F to produce molecular nitrogen and water, common atmospheric constituents, in the following reaction:

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

In the SNCR process, the ammonia or urea is injected into the combustion chamber, where the combustion gas temperature is in the proper range for the reaction. Relative to catalytic control devices, SNCR is inexpensive and easy to install, particularly in new applications where the injection points can be placed for optimum mixing of ammonia and combustion gases. The reduction reaction between ammonia and NO is favored over other chemical reactions at the appropriate combustion temperatures and is, therefore, a selective reaction. One major advantage of SNCR is that it is effective in combustion gases with a high particulate loading. Sanderdust combustion devices can produce exhaust that has a very high particulate loading rate from ash carryover to the downstream particulate control device. With use of SNCR, the particulate loading is irrelevant to the gas-phase reaction of the ammonia and NO.

One disadvantage of SNCR, and any control systems that rely on the ammonia and NO reaction, is that excess ammonia (commonly referred to as "ammonia slip") must be injected to ensure the highest level of control. Higher excess ammonia generally results in a higher NO$_X$ control efficiency. However, ammonia is also a contributor to atmospheric formation of particulate that can contribute to regional haze. Therefore, the need to reduce NO$_X$ emissions must be balanced with the need to keep ammonia slip levels acceptable. Careful monitoring to ensure an appropriate level of ammonia slip, not too high or too low, is necessary.

Additionally, in applications where SNCR is retrofitted to an existing combustion chamber (i.e., an existing boiler), substantial care must be used when selecting injection locations. This is because proper mixing of the injected ammonia cannot always be achieved in a retrofit, possibly due to space limitations inside the boiler itself. For this reason, in retrofit applications it is common to achieve control efficiencies toward the lower end (25 percent) of the SNCR control efficiency range previously mentioned. It is important to note that the Line 2 boiler has a small combustion chamber (common among type “D” boilers). The small combustion chamber, as noted above, will make retrofitting difficult, if not impossible.

Sanderdust-fired burner applications present further challenges for use of SNCR control systems. It is unlikely that the burner, in both the Line 2 boiler and GFD, would have the residence time needed at the critical temperatures for the proper reduction reaction to take place. In order to determine the appropriate residence time for the reaction and to ensure enough residence time exists, additional studies would be necessary to conclude whether SNCR is a technically feasible control option. Another concern for SNCR implementation, on the GFD only, is that ammonia can darken or blacken certain wood species. It is unknown what impact ammonia would have on the wood species being used by Woodgrain for the period of time it would be exposed, the concentrations of ammonia slip, and at the elevated temperatures that occur in the GFD. Due to these concerns, SNCR is not considered an applicable technology with proven feasibility for the sanderdust combustion devices at the facility.

To further highlight that SNCR control technology is likely technically infeasible for sanderdust-fired burner applications, MFA conducted a search of the USEPA RACT/BACT/LEAR Clearinghouse database. MFA performed the search for the period between January 1, 2000 to January 1, 2020 for similar fuel-type combustion units. No instances of SNCR installations on sanderdust combustion devices were found. As a result, SNCR was excluded from further evaluation in the Analysis.

5.1.2 Selective Catalytic Reduction and Hybrid Systems

Unlike SNCR, selective catalytic reduction (SCR) reduces NO_X emissions with ammonia in the presence of a catalyst. The major advantages of SCR technology are the higher control efficiency (70 to 90 percent) and the lower temperatures at which the reaction can take place (400°F to 800°F, depending on the catalyst selected). SCR is widely used for combustion processes, such as those using natural gas turbines, where the type of fuel produces a relatively clean combustion gas. In an SNCR/SCR hybrid system, ammonia or urea is injected into the combustion chamber to provide the initial reaction with NO_X emissions, followed by a catalytic (SCR) section that further enhances the reduction of NO_X emissions. The primary reactions that take place in the presence of the catalyst are:

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

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

$NO + NO_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O$

SCR is not widely used with wood-fired combustion units because of the amount of particulate that is generated by the combustion of wood. If not removed completely, the particulate can cause plugging in the catalyst and can coat the catalyst, reducing the surface area for reaction. Another challenge with wood-fired combustion is the presence of alkali metals such as sodium and potassium, which are commonly found in wood but not in fossil fuels. Sodium and potassium will poison catalysts, and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorus and arsenic.

Because of the likelihood of catalyst deactivation through particulate plugging and catalyst poisoning, SCR and SNCR/SCR hybrid systems are considered to be technically infeasible for control of NO_X emissions from wood-fired combustion units.

5.1.3 Low NOx Burner

Low NO_X burners are a viable technology for a number of fuels, including sanderdust and natural gas. Low NO_X burner technology is used to moderate and control, via a staged process, the fuel and air mixing rate in the combustion zone. This modified mixing rate reduces the oxygen available for thermal NO_X formation in critical NO_X formation zones, and/or decreases the amount of fuel burned at peak flame temperatures. These techniques are also referred to as staged combustion or sub-stoichiometric combustion to limit NO_X formation.

Potential reductions in NO_X emissions from the direct wood-fired burners (without add-on controls) are limited by the burner firebox geometry, air flow controls and burner zone stoichiometry, making retrofitting applications difficult. While these parameters can be optimized for NO_X performance and still maintain acceptable combustion performance, it is expected that facilities are already operating in this manner due to routine maintenance and tuning of the burner systems.

In order to achieve effective NO_X reductions from low NO_X burners, a complete replacement of the boiler and dryer burner system would likely be required, including fans, air control systems, and firebox. The Federal Guidance Document identifies several criteria for selecting control measures in the Analysis, including emission reductions through improved work practices, retrofits for sources with no existing controls, and upgrades or replacements for existing, less effective controls. None of these criteria identify or recommend whole replacement of emission units. Based on the challenges retrofitting the burners and the Federal Guidance Document criteria, low NO_X burners for the Line 2 boiler and GFD were excluded from further consideration in the Analysis.

5.2 Step 2—Selection of Emissions

See Sections 2.2 for descriptions of the NO_X emission units and emission rates, respectively, selected for the Analysis.

5.3 Step 3—Characterizing Cost of Compliance

No technically feasible control technologies were identified for potential control of NO_X emissions. Therefore, the cost of compliance is not applicable to this Analysis.

5.4 Step 4—Characterizing Time Necessary for Compliance

No technically feasible control technologies were identified for potential control of NO_X emissions. Therefore, the time necessary for compliance is not applicable to this Analysis.

5.5 Step 5—Characterizing Energy and Non-air Environmental Impacts

Since no technically feasible control technologies were identified for NO_X emissions, there are no energy and non-air environmental impacts to characterize.

5.6 Step 6—Characterize the Remaining Useful Life

No technically feasible control technologies were identified for NO_X emissions; therefore, no characterization of the remaining useful life is necessary for the Analysis.

6 SO_2 ANALYSIS

The Analysis for SO_2 emissions follows the six steps previously described in Section 3.

6.1 Step 1—Determine SO_2 Control Measures for Consideration

6.1.1 Dry Sorbent Injection

SO_2 scrubbers are control devices typically used on stationary utility and industrial boilers, especially those combusting high sulfur fuels such as coal or oil. SO_2 scrubbers are not common for wood-fired boiler applications because of the inherent low sulfur content of the fuel.

SO_2 scrubbers use a reagent to absorb, neutralize, and/or oxidize the SO_2 in the exhaust gas, depending on the selected reagent. In dry sorbent injection systems, powdered sorbents are pneumatically injected into the exhaust gas to produce a dry solid waste. As a result, use of dry sorbent injection systems requires downstream particulate control devices to remove the dry solid waste stream. This waste product, a mixture of fly ash and the reacted sulfur compounds, will require landfilling or other waste management. For sources with existing particulate control devices, retrofitting dry sorbent injection onto existing systems will increase the volume of fly ash and solid waste generated by the existing system.

Overall performance depends on the sorbent selected for injection and the exhaust gas temperature at the injection location. These parameters are driven in large part by the specific combustion unit configuration and space limitations. Control efficiencies for dry sorbent injection systems, including retrofit applications, range between 50 and 80 percent for control of SO_2 emissions. While higher control efficiencies can be achieved with dry sorbent injection in new installations or with wet SO_2 scrubber systems, the ease of installation and the smaller space requirements make dry sorbent injection systems preferable for retrofitting.

Dry sorbent injection systems introduce PM emissions into the exhaust stream, as mentioned above. This will cause increases to the particulate inlet loading of downstream particulate control devices. For retrofit applications, it is likely that modification of the downstream existing particulate control device will be necessary in order to accommodate the increased particulate inlet loading. It is anticipated that this increased loading cannot be accommodated solely through modifications to the existing control device. Assuming that this is the case, additional particulate controls will be required, resulting in cost increases and further energy and environmental impacts.

In addition, dry sorbent injection systems are commonly applied to high sulfur content fuel combustion systems, such as coal-fired boilers but not wood-fired boilers. The sulfur content of wood is quite low when compared to coal. It is also not certain that the control efficiency range, stated above, would be achievable when implemented on the emission units included in this SO_2 Analysis because of the low concentration of sulfur in the exhaust streams.

Therefore, the installation of dry sorbent injection systems on the emission units included in this SO_2 Analysis is not considered to be a feasible control option. Moreover, the potential for higher particulate emissions, which contribute to visibility issues, also suggests that dry sorbent injection should not be assessed in this Analysis.

6.2 Step 2—Selection of Emissions

See Section 2.3 for a description of the SO_2 emissions used in the Analysis.

6.3 Step 3—Characterizing Cost of Compliance

No technically feasible control technologies were identified for potential control of SO_2 emissions. Therefore, the cost of compliance is not applicable to this Analysis.

6.4 Step 4—Characterizing Time Necessary for Compliance

No technically feasible control technologies were identified for potential control of SO_2 emissions. Therefore, the time necessary for compliance is not applicable to this Analysis.

6.5 Step 5—Characterizing Energy and non-Air Environmental Impacts

Since no technically feasible control technologies were identified for SO_2 emissions, there are no energy and non-air environmental impacts to characterize.

6.6 Step 6—Characterize the Remaining Useful Life

No technically feasible control technologies were identified for SO_2 emissions; therefore, no characterization of the remaining useful life is necessary for the Analysis.

7 CONCLUSION

This report presents cost estimates associated with installing control devices at the La Grande facility in order to reduce visibility-impairing pollutants in Class I areas and provides the Four Factor Analysis conducted consistent with available DEQ and USEPA guidance documents. Woodgrain believes that the above information meets the state objectives and is satisfactory for the DEQ's continued development of the SIP as a part of the Regional Haze program.

LIMITATIONS

The services undertaken in completing this report were performed consistent with generally accepted professional consulting principles and practices. No other warranty, express or implied, is made. These services were performed consistent with our agreement with our client. This report is solely for the use and information of our client unless otherwise noted. Any reliance on this report by a third party is at such party's sole risk.

Opinions and recommendations contained in this report apply to conditions existing when services were performed and are intended only for the client, purposes, locations, time frames, and project parameters indicated. We are not responsible for the impacts of any changes in environmental standards, practices, or regulations subsequent to performance of services. We do not warrant the accuracy of information supplied by others, or the use of segregated portions of this report.

TABLES

Table 2-1

PM_{10} Evaluation for Regional Haze Four Factor Analysis

Woodgrain Millwork, Inc.— La Grande, Oregon

Emission Unit(s) (1)	Emission Unit ID(s)	Current PM_{10} Control Technology (1)	Pollution Control Device ID	Annual PM_{10} Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Evaluation	Emission Controls to be Evaluated
Green Furnish Dryer	GFD/C46	Cyclones (x2), WESP, RTO	RTO	8.04	No	Already using state of the art pollution control equipment.	--
Line 2 Press	P2	RCO	RCO	6.86	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Line 1 Press	P1	RCO	RCO	6.34	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Line 2 Boiler	B2	Dry ESP	DESP	5.11	No	Emission Unit is directly regulated for filterable PM as a surrogate for metal under Boiler MACT, which became effective after July 31, 2013. Therefore, this emission unit meets EPA guidance for no further analysis.	--
Transfer to Line 1 Storage Cyclone (MS)	C4	--	--	3.51	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Line 1 Reject Bin (BF)	C23	--	--	2.36	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Line 1 Boiler	B1	Good Combustion Practices	--	1.40	No	Emission Unit is directly regulated for filterable PM as a surrogate for metal under Boiler MACT, which became effective after July 31, 2013. Therefore, this emission unit meets EPA guidance for no further analysis.	--
Green Furnish Dryer Sanderdust Feed Bin	C47	Baghouse	BH21	1.34	Yes	--	Venturi Scrubbers, Electrostatic Precipitator
Line 2 Board Cooler	BC2	--	--	1.25	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Line 1 Board Cooler	BC1	--	--	1.15	Yes	--	Baghouses, Venturi Scrubbers, Electrostatic Precipitator
Natural Gas in Line 2 Dryer	--	Baghouses	BH28 / BH29	0.26	Yes	--	Venturi Scrubbers, Electrostatic Precipitator
Natural Gas in Line 1 Dryer	--	Baghouses	BH25 / BH26	0.21	Yes	--	Venturi Scrubbers, Electrostatic Precipitator
All Other Emission Units	Varies	Varies per Emission Unit	--	4.25	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014 by the Oregon DEQ.

Table 2-2
NO_X Evaluation for Regional Haze Four Factor Analysis
Woodgrain Millwork, Inc.— La Grande, Oregon

Emission Unit(s) (1)	Emission Unit ID(s)	Current NO_X Control Technology (1)	Annual NO_X Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Evaluation	Emission Controls to be Evaluated
Line 2 Boiler	B2	--	222	Yes	--	Selective Catalytic Reduction, Selective Non-Catalytic Reduction, Low-NOx Burners
Green Furnish Dryer	GFD/C46	--	145	Yes	--	Selective Catalytic Reduction, Selective Non-Catalytic Reduction, Low-NOx Burners
All Other Emission Units	Varies	--	12.5	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014 by the Oregon DEQ.

Table 2-3
SO_2 Evaluation for Regional Haze Four Factor Analysis
Woodgrain Millwork, Inc.— La Grande, Oregon

Emission Unit(s) (1)	Emission Unit ID(s)	Current SO_2 Control Technology (1)	Annual SO_2 Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Evaluation	Emission Controls to be Evaluated
Line 2 Boiler	B2	--	1.29	Yes	--	Dry Sorbent Injection
Green Furnish Dryer	GFD/C46	--	0.34	Yes	--	Dry Sorbent Injection
Line 1 Boiler	B1	--	0.26	Yes	--	Dry Sorbent Injection
All Other Emission Units	Varies	--	1.09	No	These emission units fall below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	--

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014 by the Oregon DEQ.

Table 2-4
Emissions Unit Input Assumptions and Exhaust Parameters
Woodgrain Millwork, Inc. — La Grande, Oregon

Emission Unit ID	Emission Unit Description	Pollution Control Device ID	Control Evaluation Proposed? (Yes/No)			Heat Input Capacity (MMBtu/hr)	Exhaust Parameters				
							Exit Temperature (°F)	Density Factor		Exit Flowrate	
			PM_{10} (1)	NO_X (2)	SO_2 (3)			Elevation	Temperature	(acfm)	(dscfm)
B1	Line 1 Boiler	--	No	No	Yes	56.0 (4)	448.0 (7)	0.9053 (a)	0.584 (b)	18,924 (c)	10,000 (7)
B2	Line 2 Boiler	DESP	No	Yes	Yes	80.0 (4)	646.3 (8)	--	--	30,925 (8)	11,680 (8)
GFD/C46	Green Furnish Dryer	RTO	No	Yes	Yes	134 (d)	240.7 (11)	--	--	59,610 (11)	34,468 (11)
P1 & P2	Line 1 and Line 2 Press Vents	RCO	Yes	No	No	--	142 (7)	0.9053 (a)	0.881 (b)	98,280 (c)	78,371 (7)
C4	Transfer to Line 1 Storage	C4	Yes	No	No	--	70.0 (12)	0.9053 (a)	1.000 (b)	44,184 (c)	40,000 (13)
C23	Line 1 Reject Bin	C23	Yes	No	No	--	70.0 (12)	0.9053 (a)	1.000 (b)	44,184 (c)	40,000 (13)
C47	GFD Sanderdust Feed Bin	BH21	Yes	No	No	--	70.0 (12)	0.9053 (a)	1.000 (b)	44,184 (c)	40,000 (14)
BC1	Line 1 Board Cooler	--	Yes	No	No	--	--	--	--	61,640 (15)	53,000 (15)
--	Line 1 Board Cooler - Roof Vent 1	BC11	--	--	--	--	105.0 (16)	0.9053 (a)	0.938 (b)	28,968 (c)	24,600 (16)
--	Line 1 Board Cooler - Roof Vent 2	BC12	--	--	--	--	100.0 (16)	0.9053 (a)	0.946 (b)	22,642 (c)	19,400 (16)
--	Line 1 Board Cooler - Roof Vent 3	BC13	--	--	--	--	94.0 (16)	0.9053 (a)	0.957 (b)	3,926 (c)	3,400 (16)
--	Line 1 Board Cooler - Roof Vent 4	BC14	--	--	--	--	63.0 (16)	0.9053 (a)	1.013 (b)	6,104 (c)	5,600 (16)
BC2	Line 2 Board Cooler	--	Yes	No	No	--	--	--	--	83,906 (15)	71,791 (15)
--	Line 2 Board Cooler - Roof Vent 1	BC21	--	--	--	--	94.0 (16)	0.9053 (a)	0.957 (b)	31,014 (c)	26,861 (16)
--	Line 2 Board Cooler - Roof Vent 2	BC22	--	--	--	--	113.0 (16)	0.9053 (a)	0.925 (b)	11,650 (c)	9,755 (16)
--	Line 2 Board Cooler - Roof Vent 3	BC23	--	--	--	--	116.0 (16)	0.9053 (a)	0.920 (b)	13,882 (c)	11,564 (16)
--	Line 2 Board Cooler - Roof Vent 4	BC24	--	--	--	--	96.0 (16)	0.9053 (a)	0.953 (b)	27,360 (c)	23,611 (16)
--	Natural Gas in Line 1 Dryer	BH25/BH26	Yes	No	No	--	--	--	--	91,226 (17)	74,000 (17)
--	Line 1 Core Dryer to Baghouse 25	BH25	--	--	--	--	148.0 (16)	0.9053 (a)	0.872 (b)	46,885 (c)	37,000 (16)
--	Line 1 Face Dryer to Baghouse 26	BH26	--	--	--	--	115.0 (16)	0.9053 (a)	0.922 (b)	44,340 (c)	37,000 (16)
--	Natural Gas in Line 2 Dryer	BH28/BH29	Yes	No	No	--	--	--	--	101,491 (17)	82,332 (17)
--	Line 2 Core Dryer to Baghouse 28	BH28	--	--	--	--	148.0 (16)	0.9053 (a)	0.872 (b)	52,051 (c)	41,077 (16)
--	Line 2 Face Dryer to Baghouse 29	BH29	--	--	--	--	115.0 (16)	0.9053 (a)	0.922 (b)	49,440 (c)	41,255 (16)

NOTES:

acfm = actual cubic feet per minute.
BH = baghouse.
DESP = dry electrostatic precipitator.
dscfm = dry standard cubic feet per minute.
GFD = green furnish dryer.
RCO = regenerative catalytic oxidizer.
RTO = regenerative thermal oxidizer.

(a) Elevation density factor = (1 - [6.73E-06] x [facility elevation above sea level {ft}])$^{5.258}$
Sanderdust maximum drying capacity (BDT/yr) = 2,785 (5)
(b) Temperature density factor = (530) / ([exhaust temperature {°F}] + 460)
(c) Exit flowrate (acfm) = (exit flowrate [scfm]) x (1 - [humidity ratio]) / ([elevation density factor] x [temperature density factor]); see reference (6).
(d) Heat input capacity (MMBtu/hr) = (sanderdust maximum drying capacity [BDT/yr]) x (default high heat value for wood/wood residuals [MMBtu/ton]) / (annual hours of operation [hrs/yr])

Sanderdust maximum drying capacity (BDT/yr) =	67,000	(4)
Default high heat value for wood/wood residuals (MMBtu/ton) =	17.48	(9)
Annual hours of operation (hrs/yr) =	8,760	(10)

References:

(1) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.
(2) See Table 2-2, NO_X Evaluation for Regional Haze Four Factor Analysis.
(3) See Table 2-3, SO_2 Evaluation for Regional Haze Four Factor Analysis.
(4) Title V Operating Permit no. 31-0002-TV-01 issued July 30, 2014. See Review Report.
(5) Elevation above sea level obtained from publicly available online references.
(6) Conservatively assumes no humidity ratio, and moisture and pressure density factors of 1.
(7) Information provided Woodgrain Millwork, Inc.
(8) Woodgrain Lumber Composites Maximum Achievable Control Technology (MACT) Emission Source Test Report prepared by Environmental Technical Services, Inc. dated November 13-15, 2019.
(9) Title 40 CFR Subchapter C Part 98 Subpart C. See Table C-1 "Default CO_2 Emission Factors and High Heat Values of Various Types of Fuel."
(10) Assumes continuous annual operation.
(11) Woodgrain Lumber Composites Compliance Source Test Report prepared by Environmental Technical Services, Inc. dated November 12, 2019.
(12) The process exhaust is at ambient conditions. Assumes 70°F as representative.
(13) Information provided Woodgrain Millwork, Inc. Assumes engineering estimate.
(14) The exit flowrate for Baghouse 21 is not known. As a result, the line 1 reject bin exit flowrate is assumed as a surrogate.
(15) Assumes the sum total of board cooler roof vent flowrates.
(16) Information provided in Table 3, "Source Parameters - Existing and Future" for Plywood and Composite Wood Products MACT Low-Risk Demonstration prepared by Golder Associates, Inc. dated April 2007.
(17) Assumes the sum total of dryer baghouse flowrates.

Table 3-1
Utility and Labor Rates
Woodgrain Millwork, Inc.— La Grande, Oregon

Parameter	Value (units)		
FACILITY OPERATIONS			
Annual Hours of Operation	8,760	(hrs/yr)	(1)
Annual Days of Operation	365	(day/yr)	(1)
Daily Hours of Operation	24	(hrs/day)	(1)
UTILITY COSTS			
Electricity Rate	0.057	($/kWh)	(2)
Natural Gas Rate	3.99	($/MMBtu)	(2)
Water Rate	0.22	($/gal)	(2)
Average Monthly Water Usage	1,028	(Mgal/mo)	(2)
Wastewater Treatment Rate	2.47	($/Mgal)	(a)
Wood Fuel Rate	0	($/ton)	(3)
Landfill Disposal Rate	81.0	($/ton)	(2)
Compressed Air Rate	0.0039	($/Mscf)	(b)
LABOR COSTS			
Maintenance Labor Rate	24.35	($/hr)	(2)
Operating Labor Rate	22.65	($/hr)	(2)
Supervisory Labor Rate	29.25	($/hr)	(2)
Operating Labor Hours per Shift	2	(hrs/shift)	(6)
Maintenance Labor Hours per Shift	1	(hrs/shift)	(6)
Shifts per Day	3	(shifts/day)	(7)

NOTES:

Mgal = thousand gallons.
MMBtu = million British thermal units.
Mscf = thousand standard cubic feet.
MWh = megawatt-hour.

(a) Wastewater treatment rate ($/Mgal) = (average wastewater treatment cost [$/mo]) / (average monthly water usage [Mgal/mo])

Average wastewater treatment cost ($/mo) = 2,538.42 (2)

(b) Compressed air cost ($-2019/Mscf) = (compressed air cost [$-1998/Mscf]) / (1998 CEPCI annual index) x (2019 CEPCI annual index)

Compressed air cost ($-1998/Mscf) = 0.0025 (4)
1998 CEPCI annual index = 389.5 (5)
2019 CEPCI annual index = 607.5 (5)

REFERENCES:

(1) Assumes continuous annual operation.
(2) Information provided by Woodgrain Millwork, Inc.
(3) Information provided by Woodgrain Millwork, Inc. The facility does not purchase wood fuel from offsite.
(4) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. Cost presented in section 1.5.1.8 assumed to be representative.
(5) See Chemical Engineering magazine, CEPCI section for annual indices.
(6) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See table 1.5.1.1 and 1.5.1.3. Conservatively assumes the minimum labor requirement of range presented.
(7) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See table 1.11. Assumes operator shifts per day as representative.

Table 4-2
Cost Effectiveness Derivation for Baghouse Installation
Woodgrain Millwork, Inc.— La Grande, Oregon

Emission Unit ID	Emission Unit Description	Input Parameters		Pollutant Removed by Control Device [(a)] (tons/yr)	Operating Parameter	
		Exhaust Flowrate [(1)] (acfm)	PM_{10} Annual Emissions Estimate [(2)] (tons/yr)		Electrical Requirements [(4)] (kW)	Number of Filter Bags Required [(4)]
P1 & P2	Line 1 and Line 2 Press Vents	98,280	13.2	13.1	382	1,239
C4	Transfer to Line 1 Storage	44,184	3.51	3.48	180	557
C23	Line 1 Reject Bin	44,184	2.36	2.34	180	557
C47	GFD Sanderdust Feed Bin	44,184	1.34	1.33	180	557
BC2	Line 2 Board Cooler	83,906	1.25	1.24	328	1,058
BC1	Line 1 Board Cooler	61,640	1.15	1.14	245	777

Emission Unit ID	Emission Unit Description	Direct Costs			Total Indirect Costs [(d)]	Total Capital Investment [(e)]	Capital Recovery Cost (CRC)				Direct Annual Costs							Total Direct Annual Costs [(14)]	Total Indirect Annual Costs [(o)]	Total Annual Cost [(p)]	Annual Cost Effectiveness [(q)]
		Purchased Equipment Cost		Total Direct Cost [(c)]			Control Device (CRC) [(f)]	Replacement Parts			Operating Labor		Maintenance		Utilities						
		Basic Equip./Services Cost [(4)]	Total [(b)]					Filter Bag Cost [(4)]	Bag Labor Cost [(h)]	Filter Bag (CRC) [(i)]	Operator Cost [(j)]	Supervisor Cost [(k)]	Labor Cost [(j)]	Material Cost [(14)]	Electricity Cost [(l)]	Compressed Air Cost [(m)]	Landfill Cost [(n)]				
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC_D	C_B	C_L	CFC_B	--	--	--	--	--	--	--	DAC	IAC	TAC	($/ton)
P1 & P2	Line 1 and Line 2 Press Vents	$332,342	$392,164	$682,366	$176,474	**$858,839**	$67,462	$18,674	$7,542	$7,769	$49,604	$7,441	$26,663	$26,663	$189,302	$201,419	$1,059	$509,919	$168,038	**$677,957**	**$51,879**
C4	Transfer to Line 1 Storage	$162,624	$191,897	$333,900	$86,354	**$420,254**	$33,011	$8,402	$3,391	$3,495	$49,604	$7,441	$26,663	$26,663	$89,105	$90,553	$282	$293,805	$116,044	**$409,848**	**$117,824**
C23	Line 1 Reject Bin	$162,624	$191,897	$333,900	$86,354	**$420,254**	$33,011	$8,402	$3,391	$3,495	$49,604	$7,441	$26,663	$26,663	$89,105	$90,553	$189	$293,712	$116,044	**$409,756**	**$175,260**
C47	GFD Sanderdust Feed Bin	$162,624	$191,897	$333,900	$86,354	**$420,254**	$33,011	$8,402	$3,391	$3,495	$49,604	$7,441	$26,663	$26,663	$89,105	$90,553	$107	$293,630	$116,044	**$409,674**	**$308,815**
BC2	Line 2 Board Cooler	$285,053	$336,363	$585,271	$151,363	**$736,634**	$57,863	$15,943	$6,441	$6,633	$49,604	$7,441	$26,663	$26,663	$162,681	$171,961	$100	$451,746	$153,551	**$605,297**	**$489,913**
BC1	Line 1 Board Cooler	$211,795	$249,918	$434,858	$112,463	**$547,321**	$42,992	$11,712	$4,730	$4,873	$49,604	$7,441	$26,663	$26,663	$121,641	$126,327	$92	$363,303	$131,108	**$494,411**	**$433,511**

See notes and formulas on following page.

Table 4-2 (Continued)
Cost Effectiveness Derivation for Baghouse Installation
Woodgrain Millwork, Inc.— La Grande, Oregon

NOTES:

(a) Pollutant removed by control device (tons/yr) = (PM_{10} annual emissions estimate [tons/yr]) x (baghouse control efficiency [%] / 100)
Baghouse control efficiency (%) = 99.0 (3)

(b) Total purchased equipment cost ($) = (1.18) x (basic equipment/services cost [$]); see reference (5).

(c) Total direct cost ($) = (1.74) x (total purchased equipment cost [$]) + (site preparation cost, SP [$]) + (building cost, Bldg. [$]); see reference (5).
Site preparation cost, SP ($) = 0 (6)
Building cost, Bldg. ($) = 0 (6)

(d) Total indirect cost ($) = (0.45) x (total purchased equipment cost [$]); see reference (5).

(e) Total capital investment ($) = (total direct cost [$]) + (total indirect cost [$]); see reference (5).

(f) Capital recovery cost of control device ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (7)
Control device capital recovery factor = 0.0786 (g)

(g) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs}] - 1); see reference (8).
Interest rate (%) = 4.75 (9)
Baghouse economic life (yr) = 20 (10)
Filter bag economic life (yr) = 4 (11)

(h) Bag replacement labor cost ($) = (total time required to change one bag [min/bag]) x (hr/60 min) x (number of filter bags required [bags]) x (maintenance labor rate [$/hr])
Total time required to change one bag (min/bag) = 15 (12)
Maintenance labor rate ($/hr) = 24.35 (13)

(i) Filter bag capital recovery cost ($) = ([initial filter bag cost {$}] x [1.08] + [bag replacement labor cost {$}]) x (filter bag capital recovery factor); see reference (12).
Filter bag capital recovery factor = 0.2804 (g)

(j) Operator or maintenance labor cost ($) = (staff hours per shift [hrs/shift]) x (staff shifts per day [shifts/day]) x (annual days of operation [days/yr]) x (operator or maintenance labor rate [$/hr])
Operating labor hours per shift [hrs/shift) = 2 (13)
Maintenance labor hours per shift [hrs/shift) = 1 (13)
Shifts per day (shifts/day) = 3 (13)
Annual days of operation (days/yr) = 365 (13)
Operator labor rate ($/hr) = 22.65 (13)
Maintenance labor rate ($/hr) = 24.35 (13)

(k) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (14).

(l) Annual electricity cost ($) = (electricity rate [$/kWh]) x (total power requirement [kWh]) x (annual hours of operation [hrs/yr])
Electricity rate ($/kWh) = 0.057 (13)
Annual hours of operation (hrs/yr) = 8,760 (13)

(m) Annual compressed air cost ($) = (compressed air rate [$/Mscf]) x (Mscf/1,000 scf) x (exhaust flowrate [acfm]) x (60 min/hr) x (annual hours of operation [hrs/yr])
Compressed air rate ($/Mscf) = 0.0039 (13)
Annual hours of operation (hrs/yr) = 8,760 (13)

(n) Annual landfill cost ($) = (landfill disposal rate [$/ton]) x (pollutant removed by control device [tons/yr])
Landfill disposal rate ($/ton) = 81.0 (13)

(o) Total indirect annual cost ($) = (0.60) x ([operator labor cost {$}] + [supervisor labor cost {$}] + [maintenance labor cost {$}] + [maintenance material cost {$}]) + (0.04) x (total capital investment [$]) + (capital recovery cost [$]); see reference (14).

(p) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(q) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.
(3) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-025) for baghouse (fabric filter), pulse-jet cleaned type issued July 15, 2003. Assumes minimum typical new equipment design efficiency.
(4) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. In the quote, costs and equipment requirements for three differently sized baghouses (5,000 cfm, 20,000 cfm, and 50,000 cfm) are presented. For the smallest exhaust flowrate above (MC4), these quoted data was scaled using a ratio. All other costs/data were scaled and obtained using trendline formulas. It is important to note that the quoted costs do not include the costs associated with taxes, installation of equipment, all concrete work (including excavation, engineering, plumbing, electrical construction), building/foundation upgrades, and permitting or licensing.
(5) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See Table 1.9 "Capital Cost Factors for Fabric Filters." The 1.18 factor includes instrumentation, sales tax, and freight.
(6) Conservatively assumes no costs associated with site preparation or building requirements.
(7) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(8) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(9) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(10) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.2.
(11) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. Typical bag filter life is 4 years.
(12) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.1.4.
(13) See Table 3-1, Utility and Labor Rates.
(14) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.

Table 4-3
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Woodgrain Millwork, Inc.— La Grande, Oregon

Emission Unit ID	Emission Unit Description	Input Parameters			Pollutant Removed by Control Device (a) (tons/yr)	Operating Parameter		
		Exhaust Flowrate (1)		PM_{10} Annual Emissions Estimate (2) (tons/yr)		System Pressure Drop (4) (inch w.c.)	Total Collection Plate Area Estimate (b) (ft^2)	ESP Inlet Grain Loading (c) (gr/ft^3)
		(acfm)	(scfm)					
P1 & P2	Line 1 and Line 2 Press Vents	98,280	78,371	13.2	13.1	6.00	31,348	3.6E-03
C4	Transfer to Line 1 Storage	44,184	40,000	3.51	3.5	6.00	16,000	2.1E-03
C23	Line 1 Reject Bin	44,184	40,000	2.36	2.34	6.00	16,000	1.4E-03
C47	GFD Sanderdust Feed Bin	44,184	40,000	1.34	1.33	6.00	16,000	8.1E-04
BC2	Line 2 Board Cooler	83,906	71,791	1.25	1.24	6.00	28,716	4.0E-04
BC1	Line 1 Board Cooler	61,640	53,000	1.15	1.14	6.00	21,200	5.0E-04
--	Natural Gas in Line 2 Dryer	101,491	82,332	0.26	0.25	6.00	32,933	6.7E-05
--	Natural Gas in Line 1 Dryer	91,226	74,000	0.21	0.207	6.00	29,600	6.1E-05

Emission Unit ID	Emission Unit Description	Direct Costs			Total Indirect Costs (f)	Total Capital Investment (g)	Capital Recovery Cost of Control Device (h)	Direct Annual Costs									Total Direct Annual Costs (13)	Total Indirect Annual Costs (s)	Total Annual Cost (t)	Annual Cost Effectiveness (u)
		Purchased Equipment Cost		Total Direct Cost (e)				Operating Labor			Maintenance		Utilities							
		Basic Equip./Services Cost (5)	Total (d)					Operator Cost (j)	Supervisor Cost (k)	Coordinator Cost (l)	Labor Cost (m)	Material Cost (n)	Fan Electricity Cost (o)	Oper. Electricity Cost (p)	Compressed Air Cost (q)	Landfill Cost (r)				
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC_D	--	--	--	--	--	--	--	--	--	DAC	IAC	TAC	($/ton)
P1 & P2	Line 1 and Line 2 Press Vents	$1,530,574	$1,806,077	$3,016,149	$1,029,464	**$4,045,613**	$317,785	$49,604	$7,441	$16,535	$6,416	$18,061	$52,920	$30,153	$201,419	$1,070	$383,617	$538,442	**$922,059**	**$70,559**
C4	Transfer to Line 1 Storage	$753,216	$888,795	$1,484,287	$506,613	**$1,990,900**	$156,386	$49,604	$7,441	$16,535	$6,416	$8,888	$23,791	$15,390	$90,553	$285	$218,901	$289,351	**$508,252**	**$146,114**
C23	Line 1 Reject Bin	$753,216	$888,795	$1,484,287	$506,613	**$1,990,900**	$156,386	$49,604	$7,441	$16,535	$6,416	$8,888	$23,791	$15,390	$90,553	$191	$218,807	$289,351	**$508,159**	**$217,349**
C47	GFD Sanderdust Feed Bin	$753,216	$888,795	$1,484,287	$506,613	**$1,990,900**	$156,386	$49,604	$7,441	$16,535	$6,416	$8,888	$23,791	$15,390	$90,553	$109	$218,725	$289,351	**$508,076**	**$382,991**
BC2	Line 2 Board Cooler	$1,306,724	$1,541,935	$2,575,031	$878,903	**$3,453,934**	$271,308	$49,604	$7,441	$16,535	$6,416	$15,419	$45,180	$27,622	$171,961	$101	$340,277	$466,714	**$806,991**	**$653,159**
BC1	Line 1 Board Cooler	$959,952	$1,132,743	$1,891,682	$645,664	**$2,537,345**	$199,310	$49,604	$7,441	$16,535	$6,416	$11,327	$33,190	$20,392	$126,327	$93	$271,324	$355,596	**$626,920**	**$549,699**
--	Natural Gas in Line 2 Dryer	$1,580,579	$1,865,083	$3,114,689	$1,063,097	**$4,177,786**	$328,167	$49,604	$7,441	$16,535	$6,416	$18,651	$54,648	$31,678	$207,999	$21	$392,991	$554,465	**$947,456**	**$3,745,701**
--	Natural Gas in Line 1 Dryer	$1,420,710	$1,676,438	$2,799,651	$955,569	**$3,755,220**	$294,974	$49,604	$7,441	$16,535	$6,416	$16,764	$49,121	$28,472	$186,961	$17	$361,329	$503,238	**$864,567**	**$4,181,572**

See notes and formulas on following page.

Table 4-3 (Continued)
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Woodgrain Millwork, Inc.— La Grande, Oregon

NOTES:

(a) Pollutant removed by control device (tons/yr) = (PM_{10} annual emissions estimate [tons/yr]) x (control efficiency [%] / 100)
Control efficiency (%) = 99.0 (3)

(b) Total collection plate area estimate (ft^2) = (average specific collection area [ft^2/1,000 scfm]) x (exhaust flowrate [scfm])
Average specific collection area (ft^2/1,000 scfm) = 400 (3)

(c) ESP inlet grain loading (gr/ft^3) = (PM_{10} annual emissions estimate [tons/yr]) x (2,000 lb/ton) x (7,000 gr/lb) / (exhaust flowrate [acfm]) x (hr/60 min) / (annual hours of operation [hrs/yr])
Annual hours of operation (hrs/yr) = 8,760 (6)

(d) Total purchased equipment cost ($) = (1.18) x (basic equipment/services cost [$]); see reference (7).

(e) Total direct cost ($) = (1.67) x (total purchased equipment cost [$]) + (site preparation cost, SP [$]) + (building cost, Bldg. [$]); see reference (7).
Site preparation cost, SP ($) = 0 (8)
Building cost, Bldg. ($) = 0 (8)

(f) Total indirect cost ($) = (0.57) x (total purchased equipment cost [$]); see reference (7).

(g) Total capital investment ($) = (total direct cost [$]) + (total indirect cost [$]); see reference (7).

(h) Capital recovery cost of control device($) = (total capital investment [$]) x (control device capital recovery factor); see reference (9).
Control device capital recovery factor = 0.0786 (i)

(i) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs}] - 1); see reference (10).
Interest rate (%) = 4.75 (11)
Dry ESP economic life (yr) = 20 (12)

(j) Operator labor cost ($) = (operator hours per shift [hrs/shift]) x (operating shifts per day [shifts/day]) x (annual days of operation [days/yr]) x (operator labor rate [$/hr])
Operator labor rate ($/hr) = 22.65 (6)
Operating labor hours per shift [hrs/shift) = 2 (6)
Shifts per day (shifts/day) = 3 (6)
Annual days of operation (days/yr) = 365 (6)

(k) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (13).

(l) Coordinator labor cost ($) = (1/3) x (operator labor cost [$]); see reference (13).

(m) Maintenance labor cost ($-1999) = (maintenance labor cost [$-1999]) / (1999 annual chemical engineering plant cost index) x (2019 annual chemical engineering plant cost index)
Maintenance labor cost ($-1999) 4,125 (13)
1999 annual chemical engineering plant cost index = 390.6 (14)
2019 annual chemical engineering plant cost index = 607.5 (14)

(n) Maintenance material cost ($) = (0.01) x (total purchased equipment cost [$]); see reference (13).

(o) Annual fan electricity cost ($) = (0.000181) x (exhaust flowrate [acfm]) x (system pressure drop [inch w.c.]) x (annual hours of operation [hrs/yr]) x (electricity rate [$/kWh])
Annual hours of operation (hrs/yr) = 8,760 (6)
Electricity rate ($/kWh) = 0.057 (6)

(p) Annual operating power electricity cost ($) = (1.94E-03) x (total collection plate area estimate [ft^3]) x (annual hours of operation [hrs/yr]) x (electricity rate [$/kWh])
Annual hours of operation (hrs/yr) = 8,760 (6)
Electricity rate ($/kWh) = 0.057 (6)

(q) Annual compressed air cost ($) = (compressed air rate [$/Mscf]) x (Mscf/1,000 scf) x (exhaust flowrate [acfm]) x (60 min/hr) x (annual hours of operation [hrs/yr])
Compressed air rate ($/Mscf) = 0.0039 (6)
Annual hours of operation (hrs/yr) = 8,760 (6)

(r) Annual landfill cost ($) = (4.29E-06) x (ESP inlet grain loading [gr/ft^3]) x (annual hours of operation [hrs/yr]) x (exhaust flowrate [acfm]) x (landfill disposal rate [$/ton]); see reference (13).
Annual hours of operation (hrs/yr) = 8,760 (6)
Landfill disposal rate ($/ton) = 81.0 (6)

(s) Total indirect annual cost ($) = (0.60) x ([operator labor cost {$}] + [supervisor labor cost {$}] + [maintenance labor cost {$}] + [maintenance material cost {$}]) + (0.04) x (total capital investment [$]) + (capital recovery cost [$]); see reference (13).

(t) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(u) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.
(3) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-028) for dry electrostatic precipitator, wire-plate type issued July 15, 2003. Assumes the typical collection area and minimum new equipment design control efficiency.
(4) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See section 3.2.3. Assumes the average system (including ductwork and collection system) pressure drop of range provided.
(5) PPC Industries Quotation no. 18048/18049 (Revision 0) dated September 12 and 13, 2018. MFA obtained two separate costs and equipment requirements for dry ESPs sized at 21,000 acfm and 51,000 acfm. For the smallest exhaust flowrate above (MC4), the quoted data was scaled using a ratio. All other costs/data were scaled and obtained using trendline formulas. It is important to note that the quoted costs do not include the costs associated with taxes, freight, mechanical construction, electrical work, excavation, building/foundation upgrades, and permitting or licensing.
(6) See Table 3-1, Utility and Labor Rates.
(7) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.16 "Capital Cost Factors for ESPs."
(8) Conservatively assumes no costs associated with site preparation or building requirements.
(9) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(10) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(11) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(12) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See section 3.4.2.
(13) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.21.
(14) See Chemical Engineering magazine, chemical engineering plant cost index section for annual indices.

Table 4-4
Cost Effectiveness Derivation for Wet Venturi Scrubber Installation
Woodgrain Millwork, Inc.— La Grande, Oregon

Emission Unit ID	Emission Unit Description	Input Parameters			Pollutant Removed by Control Device (a) (tons/yr)	Operating Parameter		
		Exhaust Flowrate (1)		PM_{10} Annual Emissions Estimate (2) (tons/yr)		Pump and Fan Power Requirement (b) (kW)	Inlet Grain Loading (c) (gr/ft^3)	Annual Water Demand (d) (gal/yr)
		(acfm)	(scfm)					
P1 & P2	Line 1 and Line 2 Press Vents	98,280	78,371	13.2	13.1	313	3.6E-03	1,255,511
C4	Transfer to Line 1 Storage	44,184	40,000	3.51	3.5	141	2.1E-03	379,405
C23	Line 1 Reject Bin	44,184	40,000	2.36	2.34	141	1.4E-03	255,010
C47	GFD Sanderdust Feed Bin	44,184	40,000	1.34	1.33	141	8.1E-04	144,696
BC2	Line 2 Board Cooler	83,906	71,791	1.25	1.2	267	4.0E-04	127,364
BC1	Line 1 Board Cooler	61,640	53,000	1.15	1.14	196	5.0E-04	118,147
--	Natural Gas in Line 2 Dryer	101,491	82,332	0.26	0.25	323	6.7E-05	24,722
--	Natural Gas in Line 1 Dryer	91,226	74,000	0.21	0.21	290	6.1E-05	20,207

Emission Unit ID	Emission Unit Description	Direct Costs			Total Indirect Costs (h)	Total Capital Investment (i)	Capital Recovery Cost of Control Device (j)	Direct Annual Costs								Total Indirect Annual Costs (q)	Total Annual Cost (r)	Annual Cost Effectiveness (s)
		Purchased Equipment Cost		Total Direct Cost (g)				Operating Labor		Maintenance		Utilities			Total Direct Annual Costs (15)			
		Basic Equip./Services Cost (e)	Total (f)					Operator Cost (l)	Supervisor Cost (m)	Labor Cost (l)	Material Cost (15)	Electricity Cost (n)	Water Usage Cost (o)	Wastewater Treatment Cost (p)				
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC_D	--	--	--	--	--	--	--	DAC	IAC	TAC	($/ton)
P1 & P2	Line 1 and Line 2 Press Vents	$1,414,110	$1,668,650	$2,603,094	$584,028	**$3,187,122**	$301,888	$49,604	$7,441	$26,663	$26,663	$155,162	$272	$3,100	$268,905	$495,595	**$764,500**	**$58,502**
C4	Transfer to Line 1 Storage	$721,752	$851,667	$1,328,601	$298,083	**$1,626,684**	$154,081	$49,604	$7,441	$26,663	$26,663	$69,757	$82	$937	$181,146	$285,371	**$466,517**	**$134,116**
C23	Line 1 Reject Bin	$721,752	$851,667	$1,328,601	$298,083	**$1,626,684**	$154,081	$49,604	$7,441	$26,663	$26,663	$69,757	$55	$630	$180,812	$285,371	**$466,183**	**$199,395**
C47	GFD Sanderdust Feed Bin	$721,752	$851,667	$1,328,601	$298,083	**$1,626,684**	$154,081	$49,604	$7,441	$26,663	$26,663	$69,757	$31	$357	$180,516	$285,371	**$465,887**	**$351,189**
BC2	Line 2 Board Cooler	$1,295,382	$1,528,551	$2,384,539	$534,993	**$2,919,532**	$276,541	$49,604	$7,441	$26,663	$26,663	$132,469	$28	$314	$243,182	$459,545	**$702,727**	**$568,770**
BC1	Line 1 Board Cooler	$956,321	$1,128,459	$1,760,396	$394,961	**$2,155,356**	$204,158	$49,604	$7,441	$26,663	$26,663	$97,315	$26	$292	$208,003	$356,594	**$564,597**	**$495,053**
--	Natural Gas in Line 2 Dryer	$1,485,582	$1,752,986	$2,734,659	$613,545	**$3,348,204**	$317,146	$49,604	$7,441	$26,663	$26,663	$160,231	$5	$61	$270,668	$517,296	**$787,964**	**$3,115,161**
--	Natural Gas in Line 1 Dryer	$1,335,241	$1,575,584	$2,457,911	$551,454	**$3,009,366**	$285,051	$49,604	$7,441	$26,663	$26,663	$144,025	$4	$50	$254,449	$471,647	**$726,097**	**$3,511,844**

See notes and formulas on following page.

Table 4-4 (Continued)
Cost Effectiveness Derivation for Wet Venturi Scrubber Installation
Woodgrain Millwork, Inc.— La Grande, Oregon

NOTES:

(a) Pollutant removed by control device (tons/yr) = (PM_{10} annual emissions estimate [tons/yr]) x (control efficiency [%] / 100)

Control efficiency (%) = 99.0 (3)

(b) Pump and fan power requirement (kW) = (typical pump and fan power requirement [hp/1,000 cfm]) x (exhaust flowrate [acfm]) x (kW/1.341 hp)

Typical pump and fan power requirement (hp/1,000 cfm) = 4.27 (4)

(c) Inlet grain loading (gr/ft^3) = (PM_{10} annual emissions estimate [tons/yr]) x (2,000 lb/ton) x (7,000 gr/lb) / (exhaust flowrate [acfm]) x (hr/60 min) / (annual hours of operation [hrs/yr])

Annual hours of operation (hrs/yr) = 8,760 (5)

(d) Water demand (gal/yr) = (control efficiency [%] / 100) x (inlet grain loading [gr/ft^3]) x (lb/7,000 gr) x (exhaust flowrate [scfm]) x (60 min/hr) x (annual hours of operation [hrs/yr]) / (mass fraction of solids in recirculation water) / (density of water [lb/gal]); see reference (6).

Control efficiency (%) = 99.0 (3)
Annual hours of operation (hrs/yr) = 8,760 (5)
Mass fraction of solids in recirculation water = 0.20 (6)
Density of water (lb/gal) = 8.3 (5)

(e) Basic equipment/services cost ($) = (capital cost [$-2002/scfm]) x (exhaust flowrate [scfm]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 2002)

Capital cost ($-2002/scfm) = 11.75 (3)
Chemical engineering plant cost index for 2019 = 607.5 (7)
Chemical engineering plant cost index for 2002 = 395.6 (7)

(f) Total purchased equipment cost ($) = (1.18) x (basic equipment/services cost [$]); see reference (8).

(g) Total direct cost ($) = (1.56) x (total purchased equipment cost [$]) + (site preparation cost, SP [$]) + (building cost, Bldg. [$]); see reference (8).

Site preparation cost, SP ($) = 0 (9)
Building cost, Bldg. ($) = 0 (9)

(h) Total indirect cost ($) = (0.35) x (total purchased equipment cost [$]); see reference (8).

(i) Total capital investment ($) = (total direct cost [$]) + (total indirect cost [$]); see reference (10).

(j) Capital recovery cost of control device ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (11).

Control device capital recovery factor = 0.0947 (k)

(k) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs}] - 1); see reference (12).

Interest rate (%) = 4.75 (13)
Wet scrubber economic life (yr) = 15 (14)

(l) Operator or maintenance labor cost ($) = (staff hours per shift [hrs/shift]) x (staff shifts per day [shifts/day]) x (annual days of operation [days/yr]) x (staff labor rate [$/hr])

Operator labor rate ($/hr) = 22.65 (5)
Operating labor hours per shift [hrs/shift) = 2 (5)
Maintenance labor rate ($/hr) = 24.35 (5)
Maintenance labor hours per shift [hrs/shift) = 1 (5)
Shifts per day (shifts/day) = 3 (5)
Annual days of operation (days/yr) = 365 (5)

(m) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (15).

(n) Annual electricity cost ($) = (fan and pump power requirement [kWh]) x (electricity rate [$/kWh]) x (annual hours of operation [hrs/yr])

Electricity rate ($/kWh) = 0.057 (5)
Annual hours of operation (hrs/yr) = 8,760 (5)

(o) Annual water usage cost ($) = (annual water demand [gal/yr]) x (Mgal/1,000 gal) x (water rate [$/Mgal])

Water rate ($/Mgal) = 0.22 (5)

(p) Annual wastewater cost ($) = (annual water demand [gal/day]) x (Mgal/1,000 gal) x (sewage treatment rate [$/Mgal])

Sewage treatment rate ($/Mgal) = 2.47 (5)

(q) Total indirect annual cost ($) = (0.60) x ([operator labor cost {$}] + [supervisor labor cost {$}] + [maintenance labor cost {$}] + [maintenance material cost {$}]) + (0.04) x (total capital investment [$]) + (capital recovery cost [$]); see reference (15).

(r) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(s) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.
(3) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-017) for venturi scrubber issued July 15, 2003. Assumes the maximum PM control efficiency and average capital cost.
(4) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See table 2.3.
(5) See Table 3-1, Utility and Labor Rates.
(6) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See section 2.5.5.1. Assumes lower end mass fraction of range in recirculation water since water evaporated is not accounted for.
(7) See Chemical Engineering magazine, Chemical Engineering Plant Cost Index (CEPCI) for annual indices.
(8) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See table 2.8.
(9) Conservatively assumes no costs associated with site preparation or building requirements.
(10) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See equation 2.42.
(11) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(12) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(13) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(14) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See section 2.6.2.2.
(15) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 2 "Wet Scrubbers for Particulate Matter" issued July 15, 2002. See table 2.9.