



Oregon

Kate Brown, Governor

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December 23, 2019

Melissa Shepherd
Boise Cascade Wood Products, LLC
Environmental Coord.
90 S 21st Ave
Elgin, OR 97827-9614

Re: Regional Haze Four Factor Analysis; Elgin Complex

Dear Melissa Shepherd:

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

Background

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

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

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

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

Guidance provided by the U.S. Environmental Protection Agency (EPA) indicates DEQ must address 80% of the visibility impairment caused by in-state sources.² Data from the EPA and National Park Service Visibility (IMPROVE) Program monitoring sites for Oregon's 12 Class I Areas indicate that sulfates, nitrates, and coarse mass continue to be significant contributors to visibility impairment in these areas. The primary precursors of sulfates, nitrates, and coarse mass are emissions of sulfur dioxide (SO₂), nitrogen oxides (NO_x), and particulate matter (PM₁₀).

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:	31-0006
Federal Facility ID:	8170611
Facility name:	Elgin Complex
Facility Address	90 S 21ST AVE
Facility City, State, Zip	ELGIN, OR 97827-9614

Facility 2017 Emissions³

Actual (tons per year)				Potential to Emit (tons per year)			
NOx	SO2	PM-10	Total Q	NOx	SO2	PM-10	Total Q
128.2	13.0	41.1	182.3	171	39	62	272

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

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

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

prepared using the EPA guidance referenced above as well as EPA's Air Pollution Control Cost Manual⁴ 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 encourage you to share drafts with us for comments and we are prepared to engage in consultation to ensure an approvable submittal before the deadline.

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

<https://www.teleconference.att.com/servlet/AWMlogin>

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

Contact

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

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

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

Sincerely,

Ali Mirzakhali
Air Quality Division Administrator

Cc:

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

Boise Cascade Wood Products, LLC
Inland Region
90 S. 21st St.
Elgin, Oregon 97827



Boise Cascade

June 15, 2020

via email

Doug Welch
Oregon DEQ
Pendleton Office
800 SE Emigrant Ave #330
Pendleton, OR 97801

RE: AQ Regional Haze Four Factor Analysis; Elgin Complex
TV Permit 31-0006

Mr. Welch:

Oregon Department of Environmental Quality (DEQ) identified the Elgin Complex as a significant source of regional haze precursor emissions to a Class I area in Oregon, triggering the need for a four-factor analysis under the regional haze program.

Boise Cascade Wood Products, LLC consulted with AII4 Inc to complete the analysis. The regional haze four-factor analysis for the Elgin Complex is due on June 15th and is attached.

If you have questions or need additional information, please contact me at 541.437.1652 or Rhonda Smith at 541.805.9627.

Regards,

I hereby certify that the information contained in this letter and attachments are true and correct to the best of my knowledge and belief.

Dale Treib
Production Manager

Attachment: BC Elgin 4-Factor Analysis

Cc: via email w/attachment
D Pei Wu – ODEQ Air Quality Planner
R Strader, R Smith – BC

REGIONAL HAZE RULE FOUR FACTOR ANALYSIS FOR THE BOISE CASCADE WOOD PRODUCTS ELGIN PLYWOOD MILL

JUNE 2020

Prepared for:



Boise Cascade®

Boise Cascade Wood Products, LLC
90 South 21st Street
Elgin, OR 97827

Submitted to:



Oregon Department of Environmental Quality
700 NE Multnomah St.
Portland, OR 97232



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1. INTRODUCTION

The Oregon Department of Environmental Quality (DEQ) Air Quality Division is in the process of developing a state implementation plan (SIP) revision for the second planning period under the 1999 Regional Haze Rule (RHR) at 40 CFR Part 51, Subpart P. The RHR focuses on improving visibility in federal Class I areas by reducing emissions of visibility impairing pollutants. DEQ is required to update the SIP by July 2021 to address further controls that could be applied to reduce emissions of sulfur dioxide (SO₂), nitrogen oxides (NO_x), and particulate matter less than 10 microns (PM₁₀) for the 2021-2028 period. DEQ has requested that several sources within the state submit a Four Factor Analysis to examine the feasibility of additional emissions controls. This report provides the four factor analysis for the Boise Cascade Wood Products, LLC (BCWP) Elgin, Oregon Plywood Mill (Elgin Mill).

In accordance with the August 2019 Guidance on Regional Haze State Implementation Plans for the Section Implementation Period, “there is no specified outcome or amount of emission reduction or visibility improvement that is directed as the reasonable amount of progress for any Class I area.”¹ The guidance states that it may be reasonable for a state not to select an effectively controlled source for further measures and provides several examples on pages 23-25, such as sources subject to recently reviewed or promulgated federal standards, sources that combust only natural gas, and sources that are already well-controlled for SO₂ and NO_x. Therefore, this report focuses only on the most significant sources of SO₂, NO_x, and PM₁₀ emissions at the Elgin Mill.

This report provides a four factor analysis for SO₂, NO_x, and PM₁₀ emissions from the biomass boilers, veneer dryers, and plywood presses located at the Elgin Mill. Note that the studmill emission sources were shutdown in 2018 and are not included in this report. Emissions from the boilers, veneer dryers, and plywood presses comprise 95 percent of the plywood mill’s 2017 actual SO₂, NO_x, and PM₁₀ emissions. The remaining PM₁₀ emissions from permitted sources are from

¹ EPA-457/B-19-003, August 2019, “Guidance on Regional Haze State Implementation Plans for the Second Implementation Period.”

material handling sources that are already controlled by a baghouse or from fugitive sources that emit little PM₁₀, would not disperse widely from the facility, and would not be cost effective to control. For example, if we assume, based on an EPA fabric filter fact sheet², that the annual cost of a fabric filter is \$10/standard cubic feet per minute (scfm) and if the flow rate from a currently uncontrolled source is only 10,000 scfm, the cost to apply a fabric filter to any source that emits 5 tons per year (tpy) or less of PM₁₀ is at least \$20,000/ton of PM₁₀ reduced, which is not cost effective.

Although the four factor analysis does not include an evaluation of visibility impacts of additional controls, the guidance indicates that states may include an analysis of visibility impacts of potential control measures as part of their determination of whether additional controls should be required for a particular source during the second implementation period. The material handling and fugitive PM₁₀ sources not included in the four factor analysis have small actual emissions and are not likely to impact visibility in Class I areas. Emissions from these sources are not likely to travel much further than the facility's fenceline and the permit requires management procedures to be implemented to control fugitive dust emissions. For example, watering of material handling sources or unpaved roads is performed if conditions are conducive to the potential for fugitive dust being emitted off site.

In accordance with DEQ guidance, insignificant sources are not addressed in this analysis. Sections 2 through 4 provide the four factor analysis for SO₂, NO_x, and PM₁₀ emissions from the Elgin Mill biomass boilers, veneer dryers, and plywood presses. Appendix A presents the control cost calculations and Appendix B presents 2017 actual emissions data.

² <https://www3.epa.gov/ttn/catc/dir1/ff-revar.pdf>

1.1 FOUR FACTOR ANALYSIS

Pursuant to 40 CFR 51.308(f)(2)(i), DEQ has requested that the Elgin Mill address the following four factors to determine if additional emissions control measures are necessary to make reasonable progress toward natural visibility conditions at Class I areas:

- The cost of compliance
- Energy and non-air quality impacts of compliance
- The time necessary for compliance
- Remaining useful life of existing affected sources

This analysis addresses these factors for additional control options that could be applied to the most significant SO₂, NO_x, and PM₁₀ emission sources at the mill using available site-specific data, capital costs of controls from available analyses for similar sources, and operating cost estimates using methodologies in the U.S. EPA Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual. No site-specific engineering analyses were performed for this study. The analysis relies on readily available information to determine if additional emissions controls may be feasible.

1.2 SUMMARY OF SOURCES EVALUATED AND EXISTING REGULATORY REQUIREMENTS

Table 1-1 provides basic information regarding the Elgin Mill sources that were evaluated in detail. The sources evaluated in this report are already subject to regulation under several programs aimed at reducing emissions of conventional and hazardous air pollutants and are well controlled. Biomass boilers and plywood manufacturing operations are subject to National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations, which require the use of Maximum Achievable Control Technology (MACT).

Table 1-1
Summary of Sources Evaluated

Emissions Unit Description	Year Installed	Fuel Fired	Control Technology	Emissions Limits
Biomass Boilers (2) (B-1 and B-2)	1973	Biomass	Electrostatic precipitator (ESP)	0.1 gr/dscf PM 0.037 lb/MMBtu PM (MACT)
Veneer Dryers (3) (VD)	1975, 1998	Natural gas	Regenerative catalytic oxidizers (RCO)	0.1 gr/dscf PM
Plywood Presses (3) (P-O and P-N)	1964, 1968, 1995	NA	No add-on controls	0.1 gr/dscf PM

The U.S. EPA developed the RHR to meet the Clean Air Act (CAA) requirements for the protection of visibility in 156 scenic areas across the United States. The first stage of the RHR required that certain types of existing stationary sources of air pollutants evaluate Best Available Retrofit Technology (BART). Specifically, the BART provisions required states to conduct a specific evaluation of existing, older stationary sources that pre-dated the 1977 CAA Amendments and, therefore, were not originally subject to the Standards of Performance for New Stationary Sources (NSPS). The purpose of the program was to identify older emission units that contributed to haze at Class I areas and that could be retrofitted to reduce emissions and improve visibility in these areas. The BART requirement applied to emission units that fit all three of the following criteria:

1. The units came into existence between August 7, 1962 and August 7, 1977;
2. The units are located at facilities in one of 26 NSPS categories; and
3. The units have a total potential to emit (PTE) of at least 250 tons per year (tpy) of NO_x, SO₂, or PM₁₀ from all BART-era emission units at the same facility.

MACT standards that limit visibility-impairing pollutants were determined to meet the requirements for BART unless there were new cost-effective control technologies available. Per Section IV of 40 CFR Part 51, Appendix Y, Guidelines for BART Determinations under the Regional Haze Rules: “Unless there are new technologies subsequent to the MACT standards

which would lead to cost-effective increases in the level of control, [state agencies] may rely on the MACT standards for purposes of BART.” Although the Elgin Mill was not subject to BART, it is still relevant that EPA determined that sources demonstrating compliance with MACT are already well controlled for purposes of the RHR. If sources are already well-controlled and not significantly contributing to visibility impacts at nearby Class I areas, further control should not be required to reduce emissions for the second planning period of the RHR.

1.3 SUMMARY OF RECENT EMISSIONS REDUCTIONS

Since 2010, the Elgin Mill has made emissions reductions for a variety of reasons. Each of the biomass boilers is subject to the provisions of 40 CFR Part 63, Subpart DDDDD, NESHAP for Industrial Commercial, and Institutional Boilers and Process Heaters (NESHAP DDDDD or Boiler MACT). Boilers subject to NESHAP DDDDD were required to undergo a one-time energy assessment and are required to conduct tune-ups at a frequency specified by the rule. Compliance with these standards required changes to operating practices, including use of clean fuels for startup.

1.4 DOCUMENT ORGANIZATION

The document is organized as follows:

- **Section 1 – Introduction:** provides the purpose of the document and what emission units are included in the analysis.
- **Section 2 – Four-Factor Analysis for Boilers:** provides the Four Factor analysis for the biomass boilers.
- **Section 3 – Four-Factor Analysis for Veneer Dryers:** provides the Four Factor analysis for the veneer dryers.
- **Section 4 – Four-Factor Analysis for Plywood Presses:** provides the Four Factor analysis for the plywood presses.
- **Section 5 – Summary of Findings:** presents a summary of the analysis.
- **Appendix A – Control Cost Analyses**

- **Appendix B – 2017 Actual Emissions**

2. FOUR FACTOR ANALYSIS FOR BOILERS

This section of the report presents the results of a Four Factor analysis for PM₁₀, SO₂, and NO_x emitted from the Elgin Mill biomass boilers. The two boilers are each 72 MMBtu/hr biomass wet stoker units and are controlled by a common dry electrostatic precipitator (ESP). To evaluate the cost of compliance portion of the Four Factor analysis, the following steps were performed:

- identify available control technologies,
- eliminate technically infeasible options, and
- evaluate cost effectiveness of remaining controls.

The time necessary for compliance, energy and non-air environmental impacts, and remaining useful life were also evaluated.

2.1 AVAILABLE CONTROL TECHNOLOGIES

Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type on which the demonstration has occurred. The scope of potentially applicable control options for industrial boilers was determined based on a review of the RBLC database³ and knowledge of typical controls used on boilers in the wood products industry. RBLC entries that are not representative of the type of emissions unit, or fuel being fired, were excluded from further consideration. Table 2-1 summarizes the potentially feasible control technologies for biomass boilers.

³ ³ RACT/BACT/LAER Clearinghouse (RBLC). <https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information>

**Table 2-1
Control Technology Summary**

Pollutant	Controls on Biomass Boilers
PM ₁₀	Fabric filter ESP Wet scrubber
SO ₂	Wet scrubber Dry sorbent injection (DSI)
NO _x	Good combustion practices Selective non-catalytic reduction (SNCR) Selective Catalytic Reduction (SCR)

Technically feasible control technologies for biomass boilers were evaluated, considering current air pollution controls, fuels fired, and RBLC Database information. Note that fuel switching from biomass to natural gas was not evaluated because the purpose of this analysis is not to change the operation or design of the source or to evaluate alternative energy projects. The August 20, 2019 regional haze implementation guidance indicates that states may determine it is unreasonable to consider fuel use changes because they would be too fundamental to the operation and design of a source. EPA BACT guidance states that it is not reasonable to change the design of a source, such as by requiring conversion of a coal boiler to a gas turbine.⁴ It is not feasible to convert a biomass boiler at a wood products mill to a gas-fired boiler because biomass boilers at wood products mills fire the biomass residuals from the production processes.

2.1.1 Available PM₁₀ Control Technologies

The following control technologies were identified as potentially available for reducing emissions of PM₁₀ from industrial biomass boilers.

⁴ <https://www.epa.gov/sites/production/files/2015-07/documents/igccbact.pdf>

Electrostatic Precipitators

ESPs are widely used for the control of PM from a variety of combustion sources. An ESP is a particulate control device that removes particles from a gas stream by using electrical energy to charge particles either positively or negatively. The charged particles are then attracted to collector plates carrying the opposite charge. The collected particles are periodically removed from the collector plates. There are several different designs that can achieve very high overall control efficiencies. Control efficiencies typically average over 98% with control efficiencies almost as high for particle sizes of 1 micrometer or less. ESPs have been demonstrated in practice to have PM₁₀ removal efficiencies as high as those achieved by fabric filters. Two ESP designs are common: dry electrostatic precipitators and wet electrostatic precipitators. The systems are similar except that wet electrostatic precipitators use water to flush the captured particles from the collector plates.

Fabric Filters

Various types of fabric filters or bag houses have been successfully used for PM control on solid fuel-fired boilers. A fabric filter utilizes filtration to remove particles from the contaminated gas stream by passing the gas stream through the filter media, thereby depositing the suspended particles in the gas stream on fabric material. The ability of a fabric filter to collect sub-micrometer particles is due to the accumulation of dust cake onto the surface of the filter, and not the fabric itself. With the correct design and choice of fabric media, particulate matter control efficiencies of 99% or greater can be achieved even for very small particles (1 micrometer or less).

Wet Scrubbers

In wet scrubbing processes, liquid or solid particles are removed from a gas stream by transferring them to a liquid, most commonly water. The PM collection efficiency of a wet scrubber system is directly related to the amount of energy expended in contacting the gas stream with the scrubber liquid. Wet scrubbers cannot typically achieve the levels of PM and PM₁₀ reduction obtained by fabric filters and ESPs without being operated at extremely high energy input levels. In addition, wet scrubber systems often require higher levels of maintenance and generate a wastewater stream that must be treated.

2.1.2 Available SO₂ Control Technologies

Biomass boilers generally emit low levels of SO₂ because of the inherent low level of sulfur in biomass fuel. However, the following add-on control technologies were identified as potentially feasible for reducing emissions of SO₂ from industrial biomass boilers.

Wet Scrubber

In wet scrubbing processes for gaseous contaminant control, a liquid is used to remove pollutants from an exhaust stream. The removal of pollutants in the gaseous stream is done by absorption. Wet scrubbers used for this type of pollutant control are often referred to as absorbers. Wet scrubbing involves a mass transfer operation in which one or more soluble components of an acid gas are dissolved in a liquid that has low volatility under process conditions. For SO₂ control, the absorption process is chemical-based and uses an alkali solution (i.e., sodium hydroxide, sodium carbonate, sodium bicarbonate, calcium hydroxide, etc.) as a sorbent or reagent in combination with water. Removal efficiencies are affected by the chemistry of the absorbing solution as it reacts with the pollutant. Wet scrubbers may take the form of a variety of different configurations including plate or tray columns, spray chambers, and venturi scrubbers.

Dry Sorbent Injection (DSI)

DSI accomplishes removal of acid gases by injecting a dry reagent (i.e., lime or trona) into the flue gas stream and prior to PM air pollution control equipment. A flue gas reaction takes place between the reagent and the acid gases, producing neutral salts that must be removed by the PM air pollution control equipment located downstream. The process is totally “dry,” meaning it produces a dry disposal product and introduces the reagent as a dry powder. The benefits of this type of system include the elimination of liquid handling equipment requiring routine maintenance such as pumps, agitators, and atomizers. The drawbacks to using this type of system are the costs associated with the installation of a dry PM control device to collect the dry by-product, as well as ongoing operating costs to procure the sorbent material and dispose of additional dry waste. Dry sorbents can also prove challenging to maintain a very low moisture content and keep flowing.

DSI systems are typically used to control SO₂, hydrochloric acid and other acid gases on coal-fired boilers.

2.1.3 Available NO_x Control Technologies

The following add-on control technologies were identified as potentially feasible for reducing emissions of NO_x from industrial boilers.

Good Operating Practices

Good operating practices were identified in the U.S. EPA RBLC database as a control technique for industrial boilers. Examples of good operating practices include but are not limited to: following manufacturer's written instructions, operating with sufficient excess air, optimum combustion temperatures, residence time, and maintaining a good mix of combustion air and fuel.

Water/Steam Injection

The addition of an inert diluent, such as water or steam, into the high temperature region of the boiler flame controls thermal NO_x generation by quenching peak flame temperatures, thus lowering overall NO_x levels. While atomized water or steam injection can reduce NO_x formation, flame instability, condensation problems and efficiency losses result when the water-to-fuel ratio becomes too high.

Low NO_x Burners (LNB)

The use of LNB is a front-end control technology for limiting NO_x emissions. An LNB is designed to control fuel and air mixing by staging the air or fuel in multiple zones and thus limit peak flame temperatures in the burners. NO_x reduction is accomplished in an LNB by using techniques such as recycling internal gas, staging the combustion air, or injecting natural gas. These techniques would create burner temperatures that are below the peak NO_x formation temperature range, thus limiting NO_x formation, but potentially impacting CO emissions. LNB burner conversion capability may also be complicated by boiler age, configuration, and fire-box dimensions.

Flue Gas Recirculation (FGR)

FGR systems recirculate a portion of relatively cool exhaust gases back into the combustion zone to lower the peak flame temperature, thereby reducing NO_x emissions. The flame temperature is lowered as a result of the cooler recirculated air, diluting the oxygen content of the combustion air and causing the heat to be diluted in a greater mass of flue gas. FGR can be designed using an induced or external design. External FGR utilizes an external fan to recirculate the flue gases back into the combustion zone to lower peak flame temperatures. Induced FGR uses a combustion air fan to recirculate a portion of the flue gases back into the combustion zone where the flue gases and combustion air are premixed to lower the flame temperature in the burner.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a control technology for NO_x emissions that uses a reduction-oxidation reaction to convert NO_x into N₂, H₂O, and carbon dioxide (CO₂). SNCR involves injecting ammonia or urea into a combustion chamber or the flue gas stream, which must be between approximately 1,600 and 2,000°F for the chemical reaction to occur. At low loads, temperatures may be less than the optimum required for achieving NO_x reductions. For example, a unit that experiences load swings according to production demands will have a variable temperature profile. To address this concern for a boiler, multiple levels of reagent injectors can be installed. Due to the energy penalty associated with the evaporation of the reagent within the furnace, additional fuel must be combusted, resulting in increased generation of fly ash.

Wood products mill boilers are operated to track steam loads required for facility processes and are not operated under base load conditions as are utility boilers. Furnace temperature tracks steam demand. If optimal furnace temperatures cannot be consistently maintained, the ammonia or urea injection rate needed to reduce NO_x emissions will result in excess reagent being present. This ammonia will combine with chlorides and sulfur in the combustion gas and result in increased corrosion on downstream metal and heat surfaces. In addition, chlorides in the gas stream will combine with excess ammonia to create condensable PM_{2.5} particles in the flue gas, thereby increasing PM_{2.5} emissions. Ammonia emissions can also result in secondary formation of

ammonia nitrates and sulfates, which are visibility impairing pollutants. Unreacted ammonia can also become part of the exhaust stream.

Selective Catalytic Reduction (SCR)

Although SCR was not identified in the RLBC search as a technology typically employed on biomass-fired industrial boilers, it has been applied to coal-fired utility boilers. SCR is a NO_x control technology that uses a catalyst to react injected anhydrous ammonia, aqueous ammonia or urea to chemically convert NO_x into N₂ and water (H₂O). SCR employs a metal-based catalyst, such as vanadium or titanium, to increase the rate of the NO_x reduction reaction⁵. The flue gases flow into a reactor module containing the catalyst where the reagent selectively reacts with the NO_x. The reduction reactions used by SCR are effective only within a given temperature range where ammonia or urea is injected into the exhaust gases in a temperature range of 480°F – 800°F⁶. The presence of alkali metals such as sodium and potassium, which are commonly found in wood, but not fossil fuels, will poison catalysts and the effects are irreversible. Other naturally occurring catalyst poisons found in wood are phosphorous and arsenic. Therefore, it is not feasible to place an SCR upstream of a particulate control device on a biomass boiler.

Under optimum temperatures, amount of reducing agent and injection grid design, SCR can achieve 90 percent reduction of NO_x. However, ammonia slip can also occur, which refers to the emissions of unreacted ammonia due to the incomplete reaction of the reagent and NO_x. As discussed above, excess ammonia can result in formation of compounds that cause corrosion and impair visibility. Ammonia slip can also occur, which refers to the emissions of unreacted ammonia due to the incomplete reaction of the reagent and NO_x.

⁵ Chapter 2 *Selective Catalytic Reduction*, OAQPS 7th Edition (June 2019). https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf (Section 2.2.1).

⁶ Air Pollution Control Technology Fact Sheet. EPA-452/F-03-032. <https://www3.epa.gov/ttn/cat1/dir1/fscr.pdf> (pg. 1).

2.2 ELIMINATION OF TECHNICALLY INFEASIBLE OPTIONS

An available control technique may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility must be documented and show, based on physical, chemical, or engineering principles, that technical reasons would preclude the successful use of the control option on the emissions unit under review. U.S. EPA generally considers a technology to be technically feasible if it has been demonstrated and operated successfully on the same type of emissions unit under review or is available and applicable to the emissions unit type under review. If a technology has been operated on the same type of emissions unit, it is presumed to be technically feasible. However, an available technology cannot be eliminated as infeasible simply because it has not been used on the same type of unit that is under review. If the technology has not been operated successfully on the type of unit under review, its lack of “availability” and “applicability” to the particular unit type under review must be documented in order for the technology to be eliminated as technically infeasible.

PM₁₀ Emissions

Due to the typically lower PM₁₀ removal efficiencies than dry ESPs, and the generation of wastewater, this analysis does not consider the use of wet controls for PM₁₀ emissions control. Fabric filters are rarely implemented on wood-fired boilers due to risk of fire (any retrofit implementation would require a long stretch of ductwork between the economizer and the control device to reduce the risk of fire). ESPs are almost as efficient as the best fabric filters without the fire risk.⁷ ESPs can withstand higher temperatures, have a smaller footprint, use less energy, and have lower maintenance requirements and better separation efficiencies than fabric filters. Therefore, use of a fabric filter for PM₁₀ control was not considered feasible and was not evaluated. The Elgin Mill biomass boilers are already very well controlled and are subject to Boiler MACT emission limits and work practices. However, for completeness, we have evaluated addition of a polishing wet ESP for further PM₁₀ control.

⁷ https://www.biomasscenter.org/images/stories/FSE_PM_Emissions.pdf

SO₂ Emissions

The Elgin Mill biomass boiler emits very little SO₂ because biomass is an inherently low-sulfur fuel. Biomass boilers typically do not require add-on SO₂ controls unless they are burning fuels or process gases that contain significant amounts of sulfur. A wet scrubber is not feasible because the mill cannot currently treat and dispose of the associated wastewater. It may be technically feasible to inject trona prior to the ESP to achieve some SO₂ control.

NO_x Emissions

NO_x emissions from biomass boilers originate primarily from oxidation of fuel bound nitrogen⁸. The Elgin Boilers are in the biomass wet stoker subcategory under the Boiler MACT rule. Biomass is fed to the boilers above the grate, begins to combust in suspension, and then completes combustion on the grate. Low-NO_x burners and water injection are not applicable to this design. The air system is optimized during the required Boiler MACT tune-ups and FGR is not likely to provide a significant reduction in NO_x.

Add-on NO_x controls such as SNCR and SCR require a specific temperature window to be effective. These controls were developed for and have predominantly been applied to fossil fuel fired boilers. There are challenges associated with applying SNCR to an industrial biomass boiler due to variability in boiler load. Good mixing of the reagent and NO_x in the flue gas at the optimum temperature window is the key to achieving a NO_x reduction for SCR and SNCR. In biomass boilers, this temperature window is a function of the variations in fuel quality and the load on the boiler. The temperature profile in a wood-fired industrial boiler is not as constant as that of a fossil fuel-fired utility boiler. Biomass boilers at forest products mills are often subject to highly variable swings in steaming rate, fuel flow, fuel mix, and bark moisture, depending on mill steam demand, availability of bark, amount of other fuels fired, and weather conditions.

⁸ NCASI Technical Bulletin 1020, Compilation of Criteria Air Pollutant Emissions Data for Sources at Pulp and Paper Mills Including Boilers – An Update to Technical Bulletin No. 884, December 2013.

In biomass boilers, the firebox temperature varies with boiler load and fuel quality. Bark quality and moisture are not consistent. Wide variations in firebox and flue gas temperatures are associated with varying steam load and fuel mix. This causes the narrow temperature window for SNCR to vary spatially in the boiler. The variability of the SNCR temperature window is a critical issue, because of the consequences of ammonia injection outside this window. Below the temperature window, ammonia slip will occur due to incomplete reactions of the injected chemicals with the NO_x . Above the temperature window, the reducing chemicals could be combusted to form additional NO_x . Multiple injection levels must typically be installed if SNCR is applied on a biomass boiler.

Additional water, power, and boiler fuel are required to operate the SNCR system because the SNCR process reduces the thermal efficiency of the boiler. The reduction reaction uses thermal energy from the boiler, which decreases the energy available for power or heat generation. As a result, additional fuel is required for the boiler to maintain the same steam output (resulting in additional emissions of other pollutants, including greenhouse gases). Despite operational challenges, SNCR cost effectiveness was evaluated at a control efficiency of 40% and using a retrofit factor of 1.5 to account for difficulty of a potential retrofit and the need to install multiple injection points.

The feasibility of SCR application to biomass boilers is also uncertain. SCR uses a catalyst to reduce NO_x to nitrogen, water, and oxygen. SCR technology employs aqueous or anhydrous ammonia as a reducing agent that is injected into the gas stream near the economizer and upstream of the catalyst bed. The catalyst lowers the activation energy of the NO_x decomposition reaction. An ammonium salt intermediate is formed at the catalyst surface and subsequently decomposes to elemental nitrogen and water. This technology has been demonstrated mostly on large coal- and natural gas-fired combustion units in the utility industry.

In practice, SCR systems operate at NO_x control efficiencies in the range of 70 to 90% for fossil fuel utility boilers. Optimum temperatures for the SCR process range from 480 to 800°F. Due to catalyst plugging and poisoning problems associated with locating the catalyst prior to the

particulate control device, an SCR system would have to be installed after an existing particulate control device, and would likely require installation of a gas-fired flue gas re-heater to achieve the optimum reaction temperature (the flue gas temperature for biomass boilers is typically less than 480°F). This would incur associated fuel costs and pollution increases, running counter to the administration's goal to reduce greenhouse gases, assuming there is adequate space to install the size re-heater needed to raise the temperature of the exhaust gas stream to the optimum temperature of 600 °F. Despite these challenges, for purposes of this analysis, we evaluated cost effectiveness of an SCR achieving 90% control, but we incorporated a retrofit factor of 1.5 to account for the difficulty of applying SCR to a biomass boiler and the likely need to add ductwork and to replace the fan to overcome additional pressure drop through the system.

2.3 COST AND IMPACTS OF TECHNICALLY FEASIBLE CONTROL TECHNOLOGIES

Cost analyses were developed where add-on controls could be technically feasible. Budgetary estimates of capital and operating costs were determined and used to estimate the annualized costs for each control technology considering existing equipment design and exhaust characteristics. A capital cost for each control measure evaluated was based on company-specific data, previously developed industry project costs, or EPA cost spreadsheets. The cost effectiveness for each technically feasible control technology was calculated based on the annualized capital and operating costs and the amount of pollutant expected to be removed based on a typical expected control efficiency and the procedures presented in the latest version of the U.S. EPA OAQPS Control Cost Manual. An interest rate of 4.75% and the typical values for equipment life shown in the Cost Manual examples were used to calculate the capital recovery factor. A 4.75% interest rate represents the prime rate just prior to the pandemic (at the time of DEQ's request for the Four Factor Analysis) and is representative because the prime rate has varied over the past two years from the current low of 3.25% to a high of 5.5% in December 2018.

Control technologies that were evaluated and for which a cost analysis was performed are summarized in Table 2-2.

**Table 2-2
Control Technologies Evaluated for Boilers**

Emissions Unit	Fuels Fired	Existing Control Technology			Additional Control Technology Costed		
		PM ₁₀	NO _x	SO ₂	PM ₁₀	NO _x	SO ₂
Biomass Boilers (2)	Biomass	ESP	Good combustion	Low-sulfur fuel	Wet ESP	SNCR SCR	DSI

Capital, operating, and total annual cost estimates for each feasible pollution control technique are presented in Appendix A. We note that these are screening level cost estimates and are not based on detailed engineering studies of the Elgin Mill boilers. Where initial cost estimates demonstrated that a particular control technology was not cost effective, we did not attempt to refine the analysis further.

Although DEQ has not indicated what additional controls they would consider cost effective, the Elgin Mill has referenced similar analyses performed by U.S. EPA and others to get a general idea of the level above which additional controls on industrial boilers are not cost effective. As part of the 2016 CSAPR update rule⁹, U.S. EPA performed an analysis to characterize whether there were non-EGU source groups with a substantial amount of available cost-effective NO_x reductions achievable by the 2017 ozone season. They evaluated control costs for non-EGU point sources with NO_x emissions greater than 25 tpy in 2017.¹⁰ U.S. EPA did not further examine control options above \$3,400 per ton. This is consistent with the range U.S. EPA analyzed for EGUs in the proposed and final CSAPR rules and is also consistent with what the U.S. EPA has identified in previous transport rules as cost-effective, including the NO_x SIP call. Note that industrial boilers were among the source categories that the very conservative U.S. EPA cost analysis determined were above \$3,400/ton. In addition, the Western Regional Air Partnership (WRAP)

⁹ 81 Fed. Reg. 74504

¹⁰ Technical Support Document for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Docket ID EPA-HQ-OAR-2015-0500, Assessment of Non-EGU NO_x Emission Controls, Cost of Controls, and Time for Compliance, U.S. EPA, November 2015.

Annex to the Grand Canyon Visibility Transport Report (June 1999) indicated that control costs greater than \$3,000/ton were high.¹¹ The costs presented in this report were developed using conservative assumptions and are above these thresholds.

2.3.1 Site Specific Factors Limiting Implementation

Currently known, site-specific factors that would limit the feasibility and increase the cost of installing additional controls include space constraints. Note that a detailed engineering study for each of the controls evaluated in this report would be necessary before any additional controls were determined to be feasible or cost effective.

2.3.2 PM₁₀ Economic Impacts

Wet ESP for Additional Boiler PM₁₀ Control

The capital cost for a wet ESP was estimated based on the low end of the range presented in an EPA wet ESP fact sheet.¹² The operating costs are based on the EPA OAQPS Cost Manual algorithms for ESPs in Section 6, Chapter 3, dated September 1999. Assuming that a wet ESP would achieve a 99 percent reduction of the boilers' 12 tpy portion of the PM₁₀ plant site emission limit (PSEL), installing a wet ESP for additional PM₁₀ control is not cost effective. Detailed cost calculations are presented in Appendix A, Table A-1. Other environmental and energy impacts from installation of a wet ESP include water use, wastewater disposal, and additional electricity use.

¹¹ https://www.wrapair.org//forums/mtf/documents/group_reports/TechSupp/SO2Tech.htm

¹² <https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf>

**Table 2-3
Wet ESP Cost Summary**

Emissions Unit Description	Capital Cost (\$)	Annual Cost (\$/yr)	Cost Effectiveness of Controls (\$/Ton PM ₁₀)
Biomass Boilers	\$11,312,896	\$1,556,788	\$131,043

2.3.3 SO₂ Economic Impacts

Trona Injection for Boiler SO₂ Control

The capital cost for a system to inject milled trona prior to the ESP on the boilers was estimated using an April 2017 Sargent and Lundy report prepared under an U.S. EPA contract.¹³ Industry standard labor, chemical, and utility costs were used to estimate the annual cost of operating the system. Table 2-4 summarizes the capital cost, annual cost, and cost effectiveness of implementing this control technology for the boilers. The Sargent and Lundy report indicates that 50% SO₂ control can be achieved without an increase in PM emissions when injecting trona prior to an ESP. The cost of installing DSI prior to the ESP is not considered cost effective because the estimated capital cost is more than \$4 million and the cost effectiveness value is in excess of \$80,000/ton of pollutant removed, even when evaluated at the SO₂ PSEL of 39 tpy. The cost per ton would be even higher if evaluated based on the actual SO₂ emission rate from biomass. Detailed cost calculations are presented in Appendix A, Table A-2.

¹³ Sargent & Lundy LLC. 2017. *Dry Sorbent Injection for SO₂/HCl Control Cost Development Methodology*. Project 13527-001, Eastern Research Group, Inc. Chicago, IL.

**Table 2-4
Trona Injection System Cost Summary**

Emissions Unit Description	Capital Cost (\$)	Annual Cost (\$/yr)	Cost Effectiveness of Controls (\$/Ton SO ₂)
Biomass Boilers	\$5,210,403	\$1,740,873	\$89,276

2.3.4 NO_x Economic Impacts

This section describes the economic impacts associated with each NO_x add-on control option evaluated for the boilers. Note that cost effectiveness was evaluated based on the PSEL, and the cost per ton would be even higher if evaluated based on actual emissions.

SNCR for Boiler NO_x Control

The cost of installing and operating SNCR on the boilers was estimated using U.S. EPA “Air Pollution Control Cost Estimation Spreadsheet for Selective Non-Catalytic Reduction (SNCR)” (June 2019) that reflects calculation methodologies presented in the U.S. EPA Air Pollution Control Cost Manual, Section 4, Chapter 1. The spreadsheet, using algorithms presented in the control cost manual, calculates estimated capital and annualized costs of installing and operating an SNCR based on site-specific data entered, such as boiler design and operating data. Note that the cost algorithms were developed using project costs for large coal-fired utility boilers and the spreadsheets are labeled as if costs are being estimated for a coal-fired boiler. As a result, they likely underestimate costs for smaller industrial boilers as costs for large utility boilers where this technology is routinely installed may not scale to smaller, variable load industrial boilers. The U.S. EPA cost manual allows a retrofit factor of greater than one where justification is provided. A retrofit factor of 1.5 was applied to account for the need to add multiple levels of reagent injectors and to perform additional tuning of the system across variable loads.

SNCR control efficiencies vary widely, but urea-based systems typically achieve reductions from 37 to 60 percent on industrial boilers, according to the OAQPS Control Cost Manual. However, operating constraints on temperature, load, reaction time, and mixing often lead to less effective results when using SNCR in practice. Our analyses assume that SNCR would achieve 40% NO_x

control because the biomass boilers are subject to regular load swings. This control efficiency is supported by the range provided in the OAQPS Cost Manual and information publicly available from vendors.¹⁴ A formal engineering analysis would be required to ultimately determine if SNCR would be effective on the boilers. This type of analysis would include obtaining temperature and flow data, developing a model of each boiler using computational fluid dynamics, determining residence time and degree of mixing, determining placement of injectors, and testing.

Table 2-5 summarizes the estimated capital cost, annual cost, and cost effectiveness of implementing SNCR control technology. The cost analysis is based on the boilers' capacity and their 169 tpy portion of the NO_x PSEL, although actual emissions in 2017 were only 125.6 tpy. The installed cost is likely underestimated because the cost is based on combined emissions from the two units. In reality, each boiler would need its own system. However, the PSEL and all emissions data are based on the two units combined because they vent to a common ESP and stack. Installing SNCR is not considered cost effective because the capital cost is almost \$4 million and the cost effectiveness is in excess of \$3,400/ton of pollutant removed, the cost effectiveness threshold for non-EGUs used by EPA for similar studies. Detailed cost calculations are presented in Appendix A, Table A-3.

Table 2-5
SNCR Cost Summary

Emissions Unit Description	Capital Cost (\$)	Annual Cost (\$/yr)	Cost Effectiveness of Controls (\$/Ton NO_x)
Biomass Boilers	\$3,944,548	\$643,730	\$9,523

¹⁴ See for example, <https://www.eescorp.com/solutions/snrcr/>, <https://www.cecoenviro.com/selective-non-catalytic-reduction-snrcr-cca-combustion-systems>, <https://www.ftek.com/en-US/products/productssubapc/urea-snrcr>

SCR for Boiler NO_x Control

The cost of installing and operating SCR on the boilers was estimated using the U.S. EPA “Air Pollution Control Cost Estimation Spreadsheet for Selective Catalytic Reduction (SCR)” (June 2019) that reflects calculation methodologies presented in the U.S. EPA Air Pollution Control Cost Manual, Section 4, Chapter 2. The spreadsheet, using algorithms presented in the control cost manual, calculates estimated capital and annualized costs of installing and operating an SCR based on site specific data entered, such as boiler design and operating data. Note that the cost algorithms were developed based on project costs for large coal-fired utility boilers and the spreadsheets are labeled as if costs are being estimated for a coal-fired boiler. As a result, they likely underestimate costs for smaller industrial boilers as costs for large utility boilers, where this technology is routinely installed, may not scale to smaller, variable load industrial boilers. The U.S. EPA cost manual allows a retrofit factor of greater than one where justification is provided. A retrofit factor of 1.5 was applied because the EPA cost equations were developed based on utility boiler applications and to account for space constraints, additional ductwork, the need for stack reheat, and the likelihood of needing a new induced draft fan to account for increased pressure drop.

Table 2-6 summarizes the capital cost, annual cost, and cost effectiveness of implementing SCR control technology on the combined emissions of the two boilers. The cost analysis is based on the boilers’ capacity and their NO_x PSEL of 170 tpy, although actual emissions in 2017 were only 125.6 tpy. Installing an SCR is not considered cost effective because the capital cost is estimated at more than \$15 million and the cost effectiveness values are well in excess of \$3,400/ton of pollutant removed, the cost effectiveness threshold for non-EGUs used by EPA for similar studies. Detailed cost calculations are presented in Appendix A, Table A-4.

Table 2-6
SCR Cost Summary

Emissions Unit Description	Capital Cost (\$)	Annual Cost (\$/yr)	Cost Effectiveness of Controls (\$/Ton NO_x)
Biomass Boilers	\$15,684,400	\$1,450,706	\$9,538

2.3.5 Energy and Non-Air Related Impacts

The environmental and energy impacts associated with SNCR include storage of additional chemicals onsite (the reagent), ammonia slip, and generation of additional emissions due to additional fuel combustion to overcome the energy penalty associated with SNCR. The environmental and energy impacts associated with SCR include the additional fuel usage and emissions from a stack reheat system and the transport, storage, handling, and use of aqueous ammonia, a corrosive hazardous material. Ammonia poses a potential exposure health and safety risk. The spent catalyst from the SCR would be required to be periodically replaced and disposed of properly, creating residual waste that would need to be landfilled or otherwise disposed. SCR systems can have adverse air impacts due to ammonia slip, possible formation of a visible plume, oxidation of carbon monoxide (CO) to carbon dioxide (CO₂), and oxidation of SO₂ to sulfur trioxide with subsequent formation of sulfuric acid mist due to ambient or stack moisture.

2.4 TIME NECESSARY FOR COMPLIANCE

U.S. EPA allows three years plus an optional extra year for compliance with MACT standards that require facilities to install controls. The process to retrofit air pollution controls on existing facility equipment is complex. Although our analysis shows there are no additional controls that would be economically feasible, if controls are ultimately required to meet RHR requirements, facilities would need at least four years to implement them. The facility would need time to obtain corporate approval for capital funding. The affected units at the facility would have to undergo substantial re-engineering (e.g., due to space constraints) to accommodate new controls. Design, procurement, installation, and shakedown of these capital intensive projects would easily consume three years. The facility would need to engage engineering consultants, equipment vendors, construction contractors, financial institutions, and other critical suppliers. The facility would also need to initiate and execute modifications to air permits, which are often time-consuming and have an indeterminate timeline and endpoint. Lead time would be needed to procure pollution control equipment even after it is designed and a contract is finalized, and installation of controls must be aligned with mill outage schedules that are difficult to move due to the interrelationships within

corporate mill systems and the availability of contractors. The facility would need to continue to operate as much as possible while retrofitting to meet any new requirements.

Any work on the boilers themselves would need to be staggered so only one unit was out of service at a time. Staggering work on separate units at the same facility allows some level of continued operation; however, this staggering extends the overall compliance time. Extensive outages for retrofitting must be carefully planned. Only when all the critical prerequisites for the retrofit have been identified and secured, e.g., the engineering is complete and the control equipment is staged for immediate installation, can an owner afford to shut down equipment to install new controls. This takes planning and coordination both within the company, with the contractors, and with customers.

2.5 *REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES*

The emissions units included in this analysis have a remaining useful life of twenty years or more.

2.6 *CONCLUSION*

Based on the Four Factor analysis presented above, no additional controls were determined to be cost effective for the biomass boilers at the Elgin Mill.

3. FOUR FACTOR ANALYSIS FOR VENEER DRYERS

This section of the report presents the results of a Four Factor analysis for PM₁₀, SO₂, and NO_x emitted from the veneer dryers at the Elgin Mill.

3.1 *FEASIBILITY, COST, AND IMPACTS OF ADDITIONAL CONTROLS*

The scope of potentially applicable control options for plywood veneer dryers was determined based on a review of the RBLC database and knowledge of typical fuels fired and controls used in the wood products industry. The RBLC database provides only one entry for PM₁₀ (ID MT-0021), two entries for NO_x (IDs LA-0125 and LA-0259), and no entries for SO₂ emissions from plywood veneer dryers. Emissions of volatile organic compounds (VOC) associated with plywood veneer dryer hot zones are controlled with either regenerative thermal oxidizers (RTO) or regenerative catalytic oxidizers (RCO) to meet Plywood and Composite Wood Products (PCWP) NESHAP requirements for HAP emissions control. The Elgin Mill uses an RCO to control volatile HAP emissions from the veneer dryers. Although some types of wood products plants utilize PM control devices between the dryers and the RCO/RTO, veneer dryers have much lower PM emissions rates and do not use intermediate PM controls because they are not needed to protect the catalyst of an RCO or the heat exchange media of an RTO. Emissions of PM₁₀ from the veneer dryers are controlled by the RCO because the majority of the PM₁₀ is condensable.

There are no plywood veneer dryers that are equipped with traditional PM₁₀ controls and additional PM₁₀ emissions controls may not provide a meaningful reduction in emissions. However, for completeness, and because the veneer dryers' portion of the PM₁₀ PSEL is 10.8 tpy, a cost estimate to add a polishing wet ESP to control emissions the RCO is provided. The capital cost is based on the low end of the range presented in an EPA wet ESP fact sheet¹⁵ and within the range of particleboard, oriented strand board, and medium density fiberboard dryer wet ESP capital cost

¹⁵ <https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf>

data obtained by EPA as part of the PCWP MACT information collection request (ICR¹⁶). The operating costs are based on the EPA OAQPS Cost Manual algorithms for ESPs in Section 6, Chapter 3, dated September 1999. Even assuming that a wet ESP would achieve a 99 percent reduction of the dryers' portion of the PM₁₀ PSEL of 10.8 tpy, installing a wet ESP for additional PM₁₀ control is not cost effective. Detailed cost calculations are presented in Appendix A, Table A-5. Other environmental and energy impacts from installation of a wet ESP include water use, wastewater disposal, and additional electricity use.

Table 3-1
Wet ESP Cost Summary

Emissions Unit Description	Capital Cost (\$)	Annual Cost (\$/yr)	Cost Effectiveness of Controls (\$/Ton PM₁₀)
Veneer Dryers RCO	\$6,766,592	\$985,348	\$92,157

NO_x emissions from direct-fired dryers are limited using good combustion practices or low-NO_x natural gas burners. The Elgin Mill veneer dryers are fired with natural gas, and the RCO has allowable NO_x emissions of only 1.4 tpy. Therefore, it is already low-emitting and there is no additional control technology that would be cost effective.

Insignificant SO₂ emissions are expected from veneer dryers (0.1 tpy or less). Therefore, there are no control technologies to evaluate for SO₂ emissions from plywood veneer dryers.

3.2 TIME NECESSARY FOR COMPLIANCE

U.S. EPA allows three years plus an optional extra year for compliance with MACT standards that require facilities to install controls. Although our analysis shows there are no additional controls

¹⁶ The ICR database is available in the rulemaking docket at <https://www.regulations.gov/docket?D=EPA-HQ-OAR-2016-0243>

that would be economically feasible, if controls are ultimately required to meet RHR requirements, facilities would need at least four years to implement them for the reasons discussed in Section 2.

3.3 *REMAINING USEFUL LIFE OF EXISTING AFFECTED SOURCES*

The emissions units included in this analysis have a remaining useful life of twenty years or more.

3.4 *CONCLUSION*

Based on the Four Factor analysis presented above, no additional controls were determined to be economically feasible for the Elgin Mill veneer dryers.

4. FOUR FACTOR ANALYSIS FOR PLYWOOD PRESSES

Plywood presses emit fugitive VOC and PM₁₀ as sheets of wood veneer are pressed together using hot platens; they do not emit NO_x or SO₂. 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)¹⁷ also includes fugitive emissions from other different types of process units in the same building. Nevertheless, estimated plywood press PM₁₀ emissions are fairly small (less than 15 tpy).

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, 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 certain 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).”¹⁸ By virtue of issuing emission control standards only for certain reconstituted wood products presses, EPA essentially determined that emissions capture and control is practicable for other types of presses, but not plywood presses. In the September 2019 PCWP NESHAP risk and technology review proposal, EPA determined risk from the PCWP source category is acceptable and did not propose to add standards for plywood presses.

¹⁷ 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.

¹⁸ EPA, “National Emission Standards for Hazardous Air Pollutants for Plywood and Composite Wood Products Manufacturing— Background Information for Final Standards.” February 2004.

The RBLC includes no entries for plywood presses with add-on emissions controls. The EPA 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 PM₁₀ emissions.

Plywood presses are fugitive sources, although some 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 evacuate building air. When the process and building ventilation layouts were designed, the possibility of emissions capture or testing was not contemplated and is impracticable for these existing sources.

Plywood presses are not enclosed because they are constantly 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. Each batch of pressed plywood is removed from the area using a forklift. Accordingly, forklifts are entering the press unloader continuously. 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, reduced egress, heat, and emissions).

There are no technically feasible controls to reduce plywood press PM₁₀ emissions. Therefore, the cost of controls has not been evaluated.

5. SUMMARY OF FINDINGS

The largest emission sources at the Elgin Mill are already well-controlled and are subject to various stringent individual source emission limits. However, in response to a request from DEQ, the Elgin Mill evaluated whether additional emissions controls for SO₂, NO_x, and PM₁₀ are feasible for significant emissions units.

As part of the analysis, the following information was reviewed: site-specific emissions and controls information, industry- and site-specific cost data, previous similar control evaluations, the EPA RBLC database, and the EPA Control Cost Manual. This analysis used the best information available in the time allotted to perform the analyses. Site-specific engineering analyses were not performed.

Our review of the best available information indicates that additional emissions controls for SO₂, NO_x, and PM₁₀ are either not technically feasible or they are not economically feasible when they may be technically feasible. Any determination that additional controls are economically feasible would need to be further justified based on a detailed engineering evaluation that fully considers site-specific factors. In addition, the following points are noted:

- Elgin Mill significant emissions units amenable to emissions capture and control are already well controlled.
- The biomass boilers included in the analysis are subject to MACT emission limits and work practice standards that directly limit emissions of PM₁₀. The boiler tune-up requirement serves to minimize NO_x emissions by promoting good combustion techniques.
- EPA will continue the required process to evaluate particulate and acid gas control technology improvements for the industrial boiler source category with its upcoming periodic technology reviews for NESHAP Subpart DDDDD sources.
- EPA determined in its CSAPR rulemaking that additional NO_x controls on non-EGU boilers are not cost effective.

- The plywood manufacturing operations are subject to MACT requirements that are currently undergoing review by EPA. Veneer dryer emissions are controlled using RCOs and plywood press emissions are not feasible to capture and control.

**APPENDIX A -
CONTROL COST ANALYSES**

Table A-1
Boise Cascade Elgin Mill
Capital and Annual Costs Associated with WESP for Biomass Boilers

CAPITAL COSTS			ANNUALIZED COSTS				
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)	
Direct Costs			Direct Annual Costs				
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>				
(a) A WESP	\$ 40 per scfm	\$4,280,000	(b) Operator ^(c)	1 hours/shift	\$33.00 per hour ^(d)	\$35,273	
(b) Instrumentation and controls	0.10 A	\$428,000	(b) Supervisor	15% of operator labor		\$5,291	
(b) Sales Tax	0.03 A	\$128,400	(b) Coordinator	33% of operator labor		\$11,640	
(b) Freight	0.05 A	\$214,000	<u>Maintenance</u>				
B Total Purchased Equipment Cost		\$5,050,400	(b) Maintenance labor ^(c)	0.5 hours/shift	\$60.00 per hour ^(d)	\$32,066	
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$50,504	
(b) Foundations and Supports	0.04 B	\$202,016	<u>Utilities</u>^(e)				
(b) Handling and Erection	0.50 B	\$2,525,200	Electricity - unknown	kW	\$0.07 per kWh ^(d)	\$0	
(b) Electrical	0.08 B	\$404,032	Total Direct Annual Costs				
(b) Piping	0.01 B	\$50,504					\$134,774
(b) Insulation for Ductwork	0.02 B	\$101,008	Indirect Annual Costs				
(b) Painting	0.02 B	\$101,008	(b) Overhead	60% Labor and Material Costs		\$80,864	
Direct Installation Cost		\$3,383,768	(b) General and administrative	2% of TCI		\$226,258	
Total Direct Costs		\$8,434,168	(b) Property taxes	1% of TCI		\$113,129	
Indirect Costs			(b) Insurance	1% of TCI		\$113,129	
(b) Engineering	0.20 B	\$1,010,080	(b) Capital recovery	0.079 x TCI		\$888,633	
(b) Construction and Field Expenses	0.20 B	\$1,010,080	Life of the control:	20 years at	4.75% interest		
(b) Contractor fees	0.10 B	\$505,040	Total Indirect Annual Costs				
(b) Start-up	0.01 B	\$50,504					\$1,422,014
(b) Performance test	0.01 B	\$50,504	Total Annual Costs				
(b) Model Study	0.02 B	\$101,008					\$1,556,788
(b) Contingencies	0.03 B	\$151,512	Cost Effectiveness (\$/ton)				
Total Indirect Costs		\$2,878,728	PM ₁₀ Control Efficiency ^(f) :	99.0%			
Total Capital Investment (TCI)		\$11,312,896	PM ₁₀ PSEL:	12 tpy	Total Annual Costs/Controlled PM ₁₀ Emissions:		
			Controlled PM ₁₀ Emissions:	11.9 tons of PM ₁₀ removed annually		\$131,043	

^(a) Wet electrostatic precipitator (WESP) capital cost based on low end of the range provided in the EPA fact sheet, which indicates capital cost of a wet ESP ranges from \$40 to \$200 per scfm. Flow rate from the ESP is 107,000 scfm.
<https://www3.epa.gov/ttn/catc/dir1/fwespwpi.pdf>

^(b) Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 6, Chapter 3, September 1999.

^(c) Based on 2017 operating hours.

^(d) Facility-specific cost.

^(e) The electricity requirement for a new WESP is not known.

^(f) Assumes installation of a WESP after the existing control equipment will achieve an additional 99% reduction in PM₁₀ emissions.

Table A-2
Elgin Biomass Boilers
Capital and Annual Costs Associated with Milled Trona DSI System with an ESP

Variable	Designation	Units	Value	Calculation
Unit Size	A	MW	13	144 MMBtu/hr, assumes 30% efficiency to convert to equivalent MW output
Retrofit Factor	B	-	1.5	Based on space constraints
Gross Heat Rate	C	Btu/kWh	37,944	Assumes 30% efficiency
SO ₂ Rate (uncontrolled)	D	lb/MMBtu	0.025	AP42 Table 1.6-2
Type of Coal	E	-		
Particulate Capture	F	-	ESP	
Sorbent	G	-	Milled Trona	
Removal Target	H	%	50	Per the Sargent and Lundy document, 50% reduction can be achieved without an increase in PM emissions.
Heat Input	J	Btu/hr	1.44E+08	144 MMBtu/hr
NSR	K	-	1.43	Milled Trona w/ ESP = if (H<40, 0.0270*H, 0.353e^(0.0280*H))
Sorbent Feed Rate	M	ton/hr	0.02	Trona = (1.2011*10^-06)*K*A*C*D
Estimated HCl Removal	V	%	92.89	Milled or Unmilled Trona w/ ESP = 60.86*H^0.1081
Sorbent Waste Rate	N	ton/hr	0.02	Trona = (0.7387+0.00185*H/K)*M
Fly Ash Waste Rate	P	ton/hr	2.09	Ash in Bark = 0.05; Boiler Ash Removal = 0.2; HHV = 4600 (A*C)*Ash*(1-Boiler Ash Removal)/(2*HHV)
Aux Power	Q	%	0.03	Milled Trona M*20/A
Sorbent Cost	R	\$/ton	170	
Waste Disposal Cost	S	\$/ton	50	
Aux Power Cost	T	\$/kWh	0.05	mill cost
Operating Labor Rate	U	\$/hr	33	Typical labor cost including all benefits

SO ₂ Control Efficiency:	50%
PSEL, tpy	39
Controlled SO ₂ Emissions:	19.5

Capital Costs				
Direct Costs				
BM (Base Module)	-	\$	\$ 4,135,241	Milled Trona if (M>25, 820000*B*M, 8300000*B*(M^0.284))
Indirect Costs				
Engineering & Construction Management	A1	\$	\$ 413,524	10% BM
Labor adjustment	A2	\$	\$ 206,762	5% BM
Contractor profit and fees	A3	\$	\$ 206,762	5% BM
Capital, engineering and construction cost subtotal	CECC	\$	\$ 4,962,289	BM+A1+A2+A3
Owner costs including all "home office" costs	B1	\$	\$ 248,114	5% CEC
Total project cost w/out AFUDC	TPC	\$	\$ 5,210,403	B1+CEC
AFUDC (0 for <1 year engineering and construction cycle)	B2	\$	0	0% of (CECC+B1)
Total Capital Investment	TCI	\$	\$ 5,210,403	CECC+B1+B2

Annualized Costs					
Fixed O&M Cost					
Additional operating labor costs	FOMO	\$	\$	137,280	(2 additional operator)*2080*U
Additional maintenance material and labor costs	FOMM	\$	\$	27,568	BM*0.01/B
Additional administrative labor costs	FOMA	\$	\$	4,449	0.03*(FOMO+0.4*FOMM)
Total Fixed O&M Costs	FOM	\$	\$	169,297	FOMO+FOMM+FOMA
Variable O&M Cost					
Cost for Sorbent	VOMR	\$	\$	30,725.6	M*R
Cost for waste disposal that includes both sorbent & fly ash waste not removed prior to sorbent injection	VOMW	\$	\$	921,346.5	(N+P)*S
Additional auxiliary power required	VOMP	\$	\$	1,807.39	Q*T*10*ton SO ₂
Total Variable O&M Cost	VOM	\$	\$	953,879.5	VOMR+VOMW+VOMP
Indirect Annual Costs					
General and Administrative	2%	of TCI	\$	104,208	
Property Tax	1%	of TCI	\$	52,104	
Insurance	1%	of TCI	\$	52,104	
Capital Recovery	7.86%	x TCI	\$	409,280	
Total Indirect Annual Costs			\$	617,696	
Life of the Control:	20	years		4.75%	interest
Total Annual Costs			\$	1,740,873	
Total Annual Costs/SO₂ Emissions			\$	89,276	

^(a)Cost information based on the April 2017 "Dry Sorbent Injection for SO₂/HCl Control Cost Development Methodology" study by Sargent & Lundy for a milled Trona system.

Table A-3. Estimated Cost of Applying SNCR to Elgin Mill Biomass Boilers
Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?	Industrial ▼	What type of fuel does the unit burn?	Coal ▼
Is the SNCR for a new boiler or retrofit of an existing boiler?	Retrofit ▼		
Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.	<div>1.5</div> <p><small>* NOTE: You must document why a retrofit factor of 1.5 is appropriate for the proposed project.</small></p>		

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?	144 MMBtu/hour								
What is the higher heating value (HHV) of the fuel?	4,600 Btu/lb								
What is the estimated actual annual fuel consumption?	216,641,087 lbs/Year								
Is the boiler a fluid-bed boiler?	No ▼								
Enter the net plant heat input rate (NPHR)	10 MMBtu/MW								
If the NPHR is not known, use the default NPHR value:	<table border="1"> <thead> <tr> <th>Fuel Type</th> <th>Default NPHR</th> </tr> </thead> <tbody> <tr> <td>Coal</td> <td>10 MMBtu/MW</td> </tr> <tr> <td>Fuel Oil</td> <td>11 MMBtu/MW</td> </tr> <tr> <td>Natural Gas</td> <td>8.2 MMBtu/MW</td> </tr> </tbody> </table>	Fuel Type	Default NPHR	Coal	10 MMBtu/MW	Fuel Oil	11 MMBtu/MW	Natural Gas	8.2 MMBtu/MW
Fuel Type	Default NPHR								
Coal	10 MMBtu/MW								
Fuel Oil	11 MMBtu/MW								
Natural Gas	8.2 MMBtu/MW								

Provide the following information for coal-fired boilers:

Type of coal burned: Bituminous ▼

Enter the sulfur content (%S) = 0.07 percent by weight
or
Select the appropriate SO₂ emission rate: Not Applicable ▼

Ash content (%Ash): 5 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost (\$/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})

365 days

Plant Elevation

2726 Feet above sea level

Inlet NO_x Emissions ($\text{NO}_{x\text{in}}$) to SNCR

0.27 lb/MMBtu

Outlet NO_x Emissions ($\text{NO}_{x\text{out}}$) from SNCR

0.162 lb/MMBtu

Estimated Normalized Stoichiometric Ratio (NSR)

2.07

*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/ft³

Concentration of reagent injected (C_{inj})

10 percent

Number of days reagent is stored (t_{storage})

14 days

Estimated equipment life

20 Years

Densities of typical SNCR reagents:

50% urea solution	71 lbs/ft ³
29.4% aqueous NH_3	56 lbs/ft ³

Select the reagent used

Urea

Enter the cost data for the proposed SNCR:

Desired dollar-year

2019

CEPCI for 2019

603.1 Enter the CEPCI value for 2019

541.7

2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

Annual Interest Rate (i)

4.75 Percent

Fuel ($\text{Cost}_{\text{fuel}}$)

28.75 \$/MMBtu

Reagent ($\text{Cost}_{\text{reag}}$)

1.66 \$/gallon for a 50 percent solution of urea*

Water ($\text{Cost}_{\text{water}}$)

0.0042 \$/gallon*

Electricity ($\text{Cost}_{\text{elect}}$)

0.0676 \$/kWh*

Ash Disposal (for coal-fired boilers only) (Cost_{ash})

48.80 \$/ton*

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =

0.015

Administrative Charges Factor (ACF) =

0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost (\$/gallon)	\$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)	2.40	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf .	
Ash Disposal Cost (\$/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm .	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Percent ash content for Coal (% weight)	9.23	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Higher Heating Value (HHV) (Btu/lb)	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Interest Rate (%)	5.5	Default bank prime rate	Used pre-COVID prime rate of 4.75%

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 =	144	MMBtu/hour	
Maximum Annual fuel consumption (mfuel) =	$(Q_B \times 1.0E6 \text{ Btu/MMBtu} \times 8760)/\text{HHV} =$	274,226,087	lbs/Year	
Actual Annual fuel consumption (Mactual) =	actual 2017 fuel use	216,641,087	lbs/Year	
Heat Rate Factor (HRF) =	NPHR/10 =	1.00		
Total System Capacity Factor (CF_{total}) =	8551 hours in 2017	0.98	fraction	
Total operating time for the SNCR (t_{op}) =	$CF_{\text{total}} \times 8760 =$	8760	hours	Based on 8760 PTE
NOx Removal Efficiency (EF) =	$(\text{NO}_{x_{\text{in}}} - \text{NO}_{x_{\text{out}}})/\text{NO}_{x_{\text{in}}} =$	40	percent	
NOx removed per hour =	$\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B =$	15.55	lb/hour	
Total NO _x removed per year =	$(\text{NO}_{x_{\text{in}}} \times \text{EF} \times Q_B \times t_{\text{op}})/2000 =$	68	tons/year	Based on PSEL
Coal Factor (Coal_F) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00		
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times (1 \times 10^6)/\text{HHV} =$	< 3	lbs/MMBtu	
Elevation Factor (ELEV _F) =	14.7 psia/P =	1.10		
Atmospheric pressure at 2726 feet above sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^*$ =	13.3	psia	
Retrofit Factor (RF) =	Retrofit to existing boiler	1.50		

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Reagent Data:

Type of reagent used

Urea

Molecular Weight of Reagent (MW) =

60.06 g/mole

Density =

71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate (m_{reagent}) =	$(\text{NOx}_{\text{in}} \times Q_{\text{B}} \times \text{NSR} \times \text{MW}_{\text{R}}) / (\text{MW}_{\text{NOx}} \times \text{SR}) =$ (where SR = 1 for NH_3 ; 2 for Urea)	52	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{\text{reagent}} / C_{\text{sol}} =$	105	lb/hour
	$(m_{\text{sol}} \times 7.4805) / \text{Reagent Density} =$	11.1	gal/hour
Estimated tank volume for reagent storage =	$(m_{\text{sol}} \times 7.4805 \times t_{\text{storage}} \times 24 \text{ hours/day}) / \text{Reagent Density} =$	3,800	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n / ((1+i)^n - 1) =$ Where n = Equipment Life and i = Interest Rate	0.0786

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times \text{NOx}_{\text{in}} \times \text{NSR} \times Q_{\text{B}}) / \text{NPHR} =$	3.8	kW/hour
Water Usage: Water consumption (q_{w}) =	$(m_{\text{sol}} / \text{Density of water}) \times ((C_{\text{stored}} / C_{\text{inj}}) - 1) =$	50	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$H_{\text{v}} \times m_{\text{reagent}} \times ((1/C_{\text{inj}}) - 1) =$	0.42	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta \text{fuel} \times \% \text{Ash} \times 1 \times 10^6) / \text{HHV} =$	4.6	lb/hour

Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ($SNCR_{cost}$) =	\$1,243,061 in 2019 dollars
Air Pre-Heater Costs (APH_{cost})* =	\$0 in 2019 dollars
Balance of Plant Costs (BOP_{cost}) =	\$1,791,207 in 2019 dollars
Total Capital Investment (TCI) =	\$3,944,548 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs ($SNCR_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEV} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times \text{ELEV} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times \text{CoalF} \times \text{BTF} \times \text{ELEV} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times \text{ELEV} \times \text{RF}$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$1,243,061 in 2019 dollars
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Air Pre-Heater Costs (APH_{cost})*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times \text{CoalF})^{0.78} \times \text{AHF} \times \text{RF}$$

Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2019 dollars
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* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP_{cost})

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{BTF} \times \text{RF}$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (\text{NO}_x\text{Removed/hr})^{0.12} \times \text{RF}$$

Balance of Plant Costs (BOP_{cost}) =	\$1,791,207 in 2019 dollars
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Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$331,913 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$311,816 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$643,730 in 2019 dollars

Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$59,168 in 2019 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$160,699 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$2,236 in 2019 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$1,837 in 2019 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$106,986 in 2019 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$987 in 2019 dollars
Direct Annual Cost =		\$331,913 in 2019 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$1,775 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$310,041 in 2019 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$311,816 in 2019 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$643,730 per year in 2019 dollars
NOx Removed =	68 tons/year
Cost Effectiveness =	\$9,523 per ton of NOx removed in 2019 dollars

Table A-4. Estimated Cost of Applying SCR to Elgin Mill Biomass Boilers
Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?

Industrial

What type of fuel does the unit burn?

Coal

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

Retrofit

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1.5

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

Complete all of the highlighted data fields:

What is the maximum heat input rate (QB)?

144 MMBtu/hour

What is the higher heating value (HHV) of the fuel?

4,600 Btu/lb

What is the estimated actual annual fuel consumption?

216,641,087 lbs/Year

Enter the net plant heat input rate (NPHR)

10 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

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

Plant Elevation

2670 Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned:

Bituminous

Enter the sulfur content (%S) =

0.07 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the **Cost Estimate** tab. Please select your preferred method:

- ☒ Method 1
☐ Method 2
☐ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR})

365 days

Number of days the boiler operates (t_{plant})

365 days

Inlet NO_x Emissions (NO_x_{in}) to SCR

0.27 lb/MMBtu

Outlet NO_x Emissions (NO_x_{out}) from SCR

0.027 lb/MMBtu

Stoichiometric Ratio Factor (SRF)

0.525

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$)

24,000 hours

Estimated SCR equipment life

20 Years*

* For industrial boilers, the typical equipment life is between 20 and 25 years.

Concentration of reagent as stored (C_{stored})

50 percent*

Density of reagent as stored (ρ_{stored})

71 lb/cubic feet*

Number of days reagent is stored ($t_{storage}$)

14 days

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Select the reagent used

Urea

Number of SCR reactor chambers (n_{scr})

1

Number of catalyst layers (R_{layer})

3

Number of empty catalyst layers (R_{empty})

1

Ammonia Slip (Slip) provided by vendor

2 ppm

Volume of the catalyst layers ($Vol_{catalyst}$)
(Enter "UNK" if value is not known)

UNK Cubic feet

Flue gas flow rate ($Q_{fluegas}$)
(Enter "UNK" if value is not known)

106633 acfm

Gas temperature at the SCR inlet (T)

650 °F

Base case fuel gas volumetric flow rate factor (Q_{fuel})

484 ft³/min-MMBtu/hour

Densities of typical SCR reagents:

50% urea solution71 lbs/ft³

29.4% aqueous NH₃56 lbs/ft³

Enter the cost data for the proposed SCR:

Desired dollar-year

2019

CEPCI for 2019

603.1 Enter the CEPCI value for 2019541.72016 CEPCI

Annual Interest Rate (i)

4.75 Percent

Reagent (Cost_{reag})

1.660 \$/gallon for 50% urea*

Electricity (Cost_{elect})

0.0676 \$/kWh

Catalyst cost (CC_{replace})

227.00 \$/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst)

Operator Labor Rate

60.00 \$/hour (including benefits)*

Operator Hours/Day

4.00 hours/day*

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.

CEPCI = Chemical Engineering Plant Cost Index

* \$1.66/gallon is a default value for 50% urea. User should enter actual value, if known.

* \$0.0676/kWh is a default value for electricity cost. User should enter actual value, if known.

* \$227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.

* \$60/hour is a default value for the operator labor rate. User should enter actual value, if known.

* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =
 Administrative Charges Factor (ACF) =

0.005
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 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, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-3_scr_cost_development_methodology.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 .	
Percent sulfur content for Coal (% weight)	1.84	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Higher Heating Value (HHV) (Btu/lb)	11,841	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/ .	
Catalyst Cost (\$/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	
Operator Labor Rate (\$/hour)	\$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6 .	
Interest Rate (Percent)	5.5	Default bank prime rate	Pre-COVID rate of 4.75 used

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	HHV x Max. Fuel Rate =	144	MMBtu/hour
Maximum Annual fuel consumption (mfuel) =	$(Q_B \times 1.0E6 \times 8760)/HHV =$	274,226,087	lbs/Year
Actual Annual fuel consumption (Mactual) =		216,641,087	lbs/Year
Heat Rate Factor (HRF) =	NPHR/10 =	1.00	
Total System Capacity Factor (CF_{total}) =	based on actual 2017 operating hours	0.976	fraction
Total operating time for the SCR (t_{op}) =	Based on 8760 PTE	8760	hours
NOx Removal Efficiency (EF) =	$(NO_{x_{in}} - NO_{x_{out}})/NO_{x_{in}} =$	90	percent
NOx removed per hour =	$NO_{x_{in}} \times EF \times Q_B =$	34.99	lb/hour
Total NO _x removed per year =	90% of the 169 tpy PSEL	152.1	tons/year
NO _x removal factor (NRF) =	EF/80 =	1.13	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	$Q_{fuel} \times Q_B \times (460 + T)/(460 + 700)n_{scr} =$	106,633	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}/Vol_{catalyst} =$	174.71	/hour
Residence Time	$1/V_{space}$	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.00	
SO ₂ Emission rate =	$(\%S/100) \times (64/32) \times 1 \times 10^6 / HHV =$	< 3	lbs/MMBtu
Elevation Factor (ELEVf) =	$14.7\ psia/P =$	1.10	
Atmospheric pressure at sea level (P) =	$2116 \times [(59 - (0.00356 \times h) + 459.7)/518.6]^{5.256} \times (1/144)^* =$	13.3	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.50	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at <https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html>.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	$(\text{interest rate}) / (1 / ((1 + \text{interest rate})^Y - 1))$, where $Y = H_{catalysts} / (t_{SCR} \times 24 \text{ hours})$ rounded to the nearest integer	0.3180	Fraction
Catalyst volume ($Vol_{catalyst}$) =	$2.81 \times Q_B \times EF_{adj} \times Slip_{adj} \times NO_{x_{adj}} \times S_{adj} \times (T_{adj}/N_{scr})$	610.36	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas} / (16\text{ft/sec} \times 60\text{ sec/min})$	111	ft ²
Height of each catalyst layer (H_{layer}) =	$(Vol_{catalyst} / (R_{layer} \times A_{catalyst})) + 1$ (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	$1.15 \times A_{catalyst}$	128	ft ²
Reactor length and width dimensions for a square reactor =	$(A_{SCR})^{0.5}$	11.3	feet
Reactor height =	$(R_{layer} + R_{empty}) \times (7ft + h_{layer}) + 9ft$	48	feet

Reagent Data:

Type of reagent used

Urea

Molecular Weight of Reagent (MW) = 60.06 g/mole

Density = 71 lb/ft³

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOX_{in} \times Q_B \times EF \times SRF \times MW_R) / MW_{NOx} =$	24	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent} / C_{sol} =$	48	lb/hour
	$(m_{sol} \times 7.4805) / \text{Reagent Density}$	5	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24) / \text{Reagent Density} =$	1,700	gallons (storage needed to store a 14 day reagent supply rounded to the nearest 100)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+i)^n / (1+i)^n - 1 =$ Where n = Equipment Life and i= Interest Rate	0.0786

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	$A \times 1,000 \times 0.0056 \times (\text{CoalF} \times \text{HRF})^{0.43} =$ where A = (0.1 x QB) for industrial boilers.	80.64	kW

Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR_{cost}) =	\$6,791,242	in 2019 dollars
Reagent Preparation Cost (RPC) =	\$2,290,831	in 2019 dollars
Air Pre-Heater Costs (APHC)* =	\$0	in 2019 dollars
Balance of Plant Costs (BPC) =	\$2,982,850	in 2019 dollars
Total Capital Investment (TCI) =	\$15,684,400	in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR_{cost})

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_b \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR_{cost}) =

\$6,791,242 in 2019 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564,000 \times (NO_{x,in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564,000 \times (NO_{x,in} \times Q_b \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =

\$2,290,831 in 2019 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69,000 \times (0.1 \times Q_b \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH_{cost}) =

\$0 in 2019 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529,000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529,000 \times (0.1 \times Q_b \times CoalF)^{0.42} \times ELEVF \times RF$$

Balance of Plant Costs (BOP_{cost}) =

\$2,982,850 in 2019 dollars

Annual Costs

Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$214,343 in 2019 dollars
Indirect Annual Costs (IDAC) =	\$1,236,363 in 2019 dollars
Total annual costs (TAC) = DAC + IDAC	\$1,450,706 in 2019 dollars

Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Catalyst Cost})$$

Annual Maintenance Cost =	$0.005 \times \text{TCI} =$	\$78,422 in 2019 dollars
Annual Reagent Cost =	$m_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$73,481 in 2019 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$47,753 in 2019 dollars
Annual Catalyst Replacement Cost =		\$14,686 in 2019 dollars
For coal-fired boilers, the following methods may be used to calculate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{\text{scr}} \times \text{Vol}_{\text{cat}} \times (\text{CC}_{\text{replace}}/\text{R}_{\text{layer}}) \times \text{FWF}$	* Calculation Method 1 selected.
Method 2 (for coal-fired industrial boilers):	$(Q_{\text{B}}/\text{NPHR}) \times 0.4 \times (\text{CoalF})^{2.9} \times (\text{NRF})^{0.71} \times (\text{CC}_{\text{replace}}) \times 35.3$	
Direct Annual Cost =		\$214,343 in 2019 dollars

Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times (\text{Operator Cost} + 0.4 \times \text{Annual Maintenance Cost}) =$	\$3,569 in 2019 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$1,232,794 in 2019 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$1,236,363 in 2019 dollars

Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$1,450,706 per year in 2019 dollars
NOx Removed =	152 tons/year
Cost Effectiveness =	\$9,538 per ton of NOx removed in 2019 dollars

Table A-5
Boise Cascade Elgin Mill
Capital and Annual Costs Associated with WESP for Dryers RCO

CAPITAL COSTS			ANNUALIZED COSTS				
COST ITEM	COST FACTOR	COST (\$)	COST ITEM	COST FACTOR	RATE	COST (\$)	
Direct Costs			Direct Annual Costs				
<u>Purchased Equipment Costs</u>			<u>Operating Labor</u>				
(a) A WESP	\$ 40 per scfm	\$2,560,000	(b) Operator ^(c)	1 hours/shift	\$33.00 per hour ^(d)	\$35,273	
(b) Instrumentation and controls	0.10 A	\$256,000	(b) Supervisor	15% of operator labor		\$5,291	
(b) Sales Tax	0.03 A	\$76,800	(b) Coordinator	33% of operator labor		\$11,640	
(b) Freight	0.05 A	\$128,000	<u>Maintenance</u>				
B Total Purchased Equipment Cost		\$3,020,800	(b) Maintenance labor ^(c)	0.5 hours/shift	\$60.00 per hour ^(d)	\$32,066	
<u>Direct Installation Costs</u>			(b) Maintenance materials	1% of purchased equipment costs		\$30,208	
(b) Foundations and Supports	0.04 B	\$120,832	<u>Utilities</u>^(e)				
(b) Handling and Erection	0.50 B	\$1,510,400	Electricity - unknown	kW	\$0.05 per kWh ^(d)	\$0	
(b) Electrical	0.08 B	\$241,664	Total Direct Annual Costs				
(b) Piping	0.01 B	\$30,208					\$114,478
(b) Insulation for Ductwork	0.02 B	\$60,416	Indirect Annual Costs				
(b) Painting	0.02 B	\$60,416	(b) Overhead	60% Labor and Material Costs		\$68,687	
Direct Installation Cost		\$2,023,936	(b) General and administrative	2% of TCI		\$135,332	
Total Direct Costs		\$5,044,736	(b) Property taxes	1% of TCI		\$67,666	
Indirect Costs			(b) Insurance	1% of TCI		\$67,666	
(b) Engineering	0.20 B	\$604,160	(b) Capital recovery	0.079 x TCI		\$531,519	
(b) Construction and Field Expenses	0.20 B	\$604,160	Life of the control:	20 years at	4.75% interest		
(b) Contractor fees	0.10 B	\$302,080	Total Indirect Annual Costs				
(b) Start-up	0.01 B	\$30,208					\$870,870
(b) Performance test	0.01 B	\$30,208	Total Annual Costs				
(b) Model Study	0.02 B	\$60,416					\$985,348
(b) Contingencies	0.03 B	\$90,624	Cost Effectiveness (\$/ton)				
Total Indirect Costs		\$1,721,856	PM ₁₀ Control Efficiency ^(f) :	99.0%			
Total Capital Investment (TCI)		\$6,766,592	PM ₁₀ PSEL:	10.8 tpy	Total Annual Costs/Controlled PM ₁₀ Emissions:		
			Controlled PM ₁₀ Emissions:	10.7 tons of PM ₁₀ removed annually		\$92,157	

(a) Wet electrostatic precipitator (WESP) capital cost based on low end of the range provided in the EPA fact sheet, which indicates capital cost of a wet ESP ranges from \$40 to \$200 per scfm. Flow rate from the RCO is 64,000 scfm. <https://www3.epa.gov/ttn/catc/dir1/fweswpwi.pdf>
Capital cost is consistent with cost for WESPs on dryers obtained by EPA for the PCWP MACT ICR.

(b) Cost information estimated based on the U.S. EPA OAQPS Control Cost Manual, Section 6, Chapter 3, September 1999.

(c) Based on 2017 operating hours.

(d) Facility-specific cost.

(e) The electricity requirement for a new WESP is not known.

(f) Assumes installation of a WESP after the existing control equipment will achieve an additional 99% reduction in PM₁₀ emissions. The estimated reduction is high because actual emissions are much lower than the PSEL.

**APPENDIX B -
2017 ACTUAL EMISSIONS**

Elgin Mill Reported 2017 Actual Emissions

Source ID	Source	Control Technology or Technique Used	Fugitive Source? (Y/N)	2017 Actual Emissions, tpy		
				PM ₁₀	SO ₂	NO _x
B-1 & B-2	Boilers (2)	Multiclones 1 & 2, Dry Electrostatic Precipitator-1	N	8.97	12	125.6
VD	Veneer Dryers (3)	Regenerative Catalytic Oxidizer	N	8.3	0.01	1.1
P-O & P-N	Presses (3)	NA	Y	9.66	--	--
C-N	Cyclones (15-17 & Target Box 9)	Baghouse	N	0.0476	--	--
S&D	Saw and debarkers	Minimize fugitive emissions	Y	1.38	--	--
SP	Storage piles	Minimize fugitive emissions	Y	0.43	--	--
CHP	Chipping	Minimize fugitive emissions	Y	1.18	--	--
UPR	Unpaved roads - Plywood	Speed limit, watering	Y	5.74	--	--



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

August 14, 2020

Rhonda Smith

RhondaSmith@bc.com

Boise Cascade Wood Products – Elgin Complex

90 S 21st Ave

Elgin, OR 97827-9614

Sent via EMAIL

Re: Round 2 Regional Haze Program, Four Factor Analysis
Boise Cascade – Elgin Complex, Title V facility 31-0006

Dear Rhonda Smith,

Thank you for submitting the four-factor analysis for your facility for Round 2 of the Regional Haze Program.

As you know, the Regional Haze Rule (40 CFR 51.308) was issued as part of the Clean Air Act on July 1, 1999. The goal of the Regional Haze program is to improve visibility conditions in Class I Areas back to natural conditions by 2064. Regional Haze is a long-term program that sets goals for visibility improvement in 10-year periods of time from 2004 through to 2064, with interim checks on visibility conditions every 5 years.

The letter DEQ sent to you regarding four factor analysis on December 23, 2019, is part of Oregon's requirements for Round 2 of the Regional Haze program, as detailed in 40 CFR 51.308(f), for the period from 2021 to 2028. DEQ used the 2017 PSELs to screen Oregon Title V and ACDP facilities for applicability to conduct four factor analyses for the 2018-2028 time period. DEQ requested the four-factor analysis under OAR 340-214-0110.

DEQ operations, planning, and permitting staff have reviewed the submitted four-factor analysis. DEQ staff in AQ planning and operations consulted with other states to strive for consistency, where appropriate, in identifying criteria and screening levels used in assessing presumed cost-effectiveness of pollution controls. The criteria that DEQ staff used to identify the emission units that require additional review and information were the following:

- Step 1: Divide emissions units for each facility into three bins:

- Bin 1. Likely cost-effective candidates. Control devices with cost less than \$10,000/ton, or those that appear to be technically feasible but for which no cost analysis was provided.
- Bin 2. Retain for further analysis. Control devices with cost more than \$10,000/ton but less than \$30,000/ton.
- Bin 3. Cost is unlikely to be reasonable. Above \$30,000/ton.
- Step 2: Adjust cost estimates to get close to an apples-to-apples comparison for EUs.
 - Bins 1 & 2. Adjust for basic factors (PSEL, interest rate, useful life).
 - Bin 3. No further analysis. Unlikely to be cost effective.

After initial review, DEQ ruled out control devices that:

- a) Cost of control was greater than \$10,000 per ton, after adjustment to current prime rate (3.25%),¹ 30 year lifetime, and emissions at PSEL, or
- b) Provided an emissions reduction (using emissions at PSEL) of less than 20 tons/year.

DEQ staff selected 43 emissions units at 17 facilities for additional review for a total of 62 control devices.

DEQ found the emissions units and control devices at your facility listed in the table below met the criteria for further analysis as outlined above.

Emission Unit(s)	Control Device	Status Note
Boilers 1, 2	SCR	
Boilers 1, 2	SNCR	The original 4FA cost estimate indicated that SNCR may be technically feasible, but with operational challenges. Please contact a vendor and provide a statement (if the vendor feels it is infeasible) or a cost estimate (if the vendor feels it is feasible).

For each of these control devices, please take one of the three actions below, and respond to DEQ by close of business, September 14, 2020.

- (1) Agree that the control device is cost effective. In this case, DEQ does not need more detailed cost analysis, and work can shift to planning for installation.
- (2) If your facility's Q/d based on actual emissions is less than the screening value of 5.00, you have the option to reduce PSELs to a level below 5.00 Q/d. Facilities with Q/d below 5.00 are not required to do further regional haze analysis or control device installation during Round 2.

¹ Per EPA Cost Control Manual, pages 14-17: https://www.epa.gov/sites/production/files/2017-12/documents/epacmcostestimationmethodchapter_7thedition_2017.pdf

- (3) Provide a site-specific cost estimate for each emissions unit and associated control device listed in the table above. DEQ prefers unit-specific vendor quotes but will consider other recent, similarly supported cost estimates. DEQ will continue to use criteria used in the first FFA screening step to evaluate the more detailed cost information facilities submit.

Please provide your response by close of business, **September 14, 2020**. Responses can be emailed to D Pei Wu (d.wu@state.or.us) and Joe Westersund (joe.westersund@state.or.us) and cc: the DEQ permit writer for your facility.

DEQ appreciates your commitment to protecting air quality and improving visibility in Oregon's National Parks and Wilderness Areas. If you have any questions about the content of this letter or need technical assistance, please feel free to contact D Pei Wu, PhD, at wu.d@deq.state.or.us or 503-229-5269.

Sincerely,



Ali Mirzakhali
Air Quality Division Administrator
Oregon Department of Environmental Quality

Cc: Karen Williams
D Pei Wu, PhD
Joe Westersund
Michael Orman
Janice Tacconi
Claudia Davis

Boise Cascade Wood Products, LLC
90 S 21st Avenue
Elgin, OR 97827



September 18, 2020

Dr. D. Wu
Department of Environmental Quality
700 NE Multnomah Street, Suite 600
Portland, OR 97232

Re: Boise Cascade Wood Products, LLC – Elgin Complex
Round 2 Regional Haze Program, Four Factor Analysis
Title V Facility 31-0006

Dr. Wu,

This letter serves as the Boise Cascade Elgin Mill's response to the Department's August 14 Round 2 Regional Haze letter requesting that we take one of three actions. Your letter indicated that SCR and SNCR control devices for our two biomass boilers met your criteria for further analysis.

Option 1 – Agree that the control device is cost effective.

Boise Cascade does not agree that NOx controls are cost effective for our two biomass boilers. DEQ's cost effectiveness threshold of \$10,000/ton based on PSELs is arbitrary and unsupported, especially given the lack of analysis showing that spending millions of dollars in capital to reduce actual NOx emissions from our biomass boilers will significantly improve visibility at the nearest Class I areas. A review of the WRAP modeling information at <http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx> shows that overall, Oregon point sources of NOx contribute very little to visibility impairment at Oregon Class I areas. The Elgin Mill's contribution to the overall Oregon point source NOx emissions inventory is likewise very small (less than 1 percent of 2017 actual point source emissions from Oregon sources per the 2017 NEI).

Option 2 – Reduce the facility's PSELs to a level below an actual Q/d of 5.00.

Boise Cascade does not wish to reduce the Elgin facility's PSELs.

Option 3 – Provide a site-specific vendor cost estimate for SNCR and SCR for the three biomass boilers.

Boise Cascade provided available site-specific information to CECO Environmental, a vendor of SNCR and SCR systems, to evaluate whether SNCR or SCR would be feasible for our two biomass boilers. CECO has stated that in order for SNCR to be effective, the furnace temperature needs to be at least 1800 °F. U.S. EPA's fact sheet

on SNCR also states that the NO_x reduction reaction occurs at temperatures between 1600 and 2100 °F (<https://www3.epa.gov/ttn/catc1/dir1/fsnscr.pdf>). Our two boilers do not operate in this temperature range. In fact, to prevent equipment damage, an alarm is triggered if the furnace temperature reaches 1600°F. Therefore, SNCR is not feasible for our two boilers.

A general discussion with CECO Environmental indicated that it could be possible to install an SCR system at the outlet of the ESP that controls particulate emissions from our two biomass boilers. They indicated that it is possible a low-temperature SCR system installed after the ESP (to avoid poisoning the catalyst with boiler ash/particulate) could achieve a NO_x reduction of 75 to 85%, but the system may only achieve 60% reduction in that location (not the 90% reduction that our four-factor analysis conservatively assumed). CECO provided a rough equipment cost estimate for installing an SCR system after the ESP on our Medford Mill's biomass boilers but we were not able to provide them with enough site-specific information in time for them to provide us with a cost for the Elgin Mill prior to the required submittal date for this response. However, CECO indicated to Medford that the expected equipment life was 20 years (not 30 years). We entered the lower control efficiency and the current prime rate into a revised cost spreadsheet based on the EPA equations used in our four-factor analysis and estimated a cost of \$9,993/ton based on the boilers' portion of the NO_x PSEL if a reduction of 75% is achieved. The cost effectiveness would be more than \$10,000/ton if a lower reduction were achieved, which is possible according to the vendor. This cost is based on several assumptions and we do not consider installation of SCR on our two biomass boilers cost effective.

Should ODEQ determine that the significant capital expenditures are cost effective, Boise Cascade will work with ODEQ to evaluate efficacy of controls on visibility in the affected Class I areas.

Please call Rhonda Smith, Environmental Engineer, at 541-437-2207 if you have any questions regarding this submittal.

Sincerely,



Dale Treib
Production Manager



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

January 21, 2021

Rhonda Smith

RhondaSmith@bc.com

Boise Cascade Wood Products, LLC - Elgin Complex

90 S 21st Ave

Elgin, OR 97827-9614

Sent via EMAIL

Re: Round 2 Regional Haze Program, Preliminary Determination of Cost Effective Controls;
Boise Cascade Wood Products, LLC - Elgin Complex, 31-0006

Dear Rhonda Smith:

Thank you for your responses to Department of Environmental Quality's (DEQ) December 23, 2019 request for four factor analysis for your facility, and DEQ's request for additional information on August 14, 2020, as DEQ gathered information on how to fulfill Round 2 of the Regional Haze Program in Oregon.

Based on the information provided in the four factor analysis, the cost information that you submitted, the additional information you provided, and the process DEQ is proposing to use to screen facilities, DEQ estimates the following controls are likely to be required at your facility:

Emissions Unit	Control Device	Target Pollutant
Boilers 1, 2	SCR	NOx

DEQ intends to proceed with a rulemaking that adopts the process for this analysis. If DEQ's proposed rules are approved by the Environmental Quality Commission, DEQ will likely require your facility to install these controls.

If you disagree with, or would like to discuss DEQ's preliminary determination as outlined in this letter, we encourage you to reach out to the DEQ now. After DEQ adopts rules, it intends to impose Round 2 regional haze requirements promptly thereafter and without additional discussion to meet federal timelines for submission of the State Implementation Plan.

DEQ appreciates your commitment to protecting air quality and improving visibility in Oregon's Class 1 Areas. If you have any questions about the content of this letter or need technical assistance, please contact Michael Orman, at michael.orman@deq.state.or.us or 503-509-8623.

Sincerely,

A handwritten signature in blue ink, appearing to read 'Ali Mirzakhali', with a stylized, flowing script.

Ali Mirzakhali
Air Quality Division Administrator
Oregon Department of Environmental Quality

Cc: Karen Williams
Joe Westersund
Michael Orman
Douglas Welch
Mark Bailey

Regional Haze 4FA \$/Ton Calculator
Boise Cascade Elgin

Facility	Emission Unit(s)	Control Device		initial capital expense	interest rate	Lifetime of control device (years)	capital recovery factor	annualized capital recovery expense	Direct Annual Costs	Indirect Annual Costs (not including capital recovery)	annual operating expenses all annual costs except capital recovery	total annual costs	Target Pollutant(s)	PSEL for target pollutant(s) (tons/year)	control efficiency	tons of pollutant reduced	\$/ton
Boise Cascade Elgin	Boilers 1 and 2	SCR	as submitted	\$15,684,400	4.75%	20	7.855%	\$1,232,017	\$214,343	\$3,569	\$217,912	\$1,449,929	NOx	168.9	90%	152.01	\$9,538
Boise Cascade Elgin	Boilers 1 and 2	SCR	adjusted	\$15,684,400	3.25%	30	5.268%	\$826,281	\$214,343	\$3,569	\$217,912	\$1,262,105	NOx	168.9	90%	152.01	\$8,303
Boise Cascade Elgin	Boilers 1 and 2	SCR		reference to quote from vendor in 9/18/2020 letter from Boise Cascade (BC did not provide details)										168.9	75%	126.68	\$9,993

Cost estimate information provided by Boise Cascade in their original 4FA:

Table 2-6
SCR Cost Summary

Emissions Unit Description	Capital Cost (\$)	Annual Cost (\$/yr)	Cost Effectiveness of Controls (\$/Ton NO _x)
Biomass Boilers	\$15,684,400	\$1,450,706	\$9,538

Cost estimate information provided by Boise Cascade in their letter dated September 18, 2020:

A general discussion with CECO Environmental indicated that it could be possible to install an SCR system at the outlet of the ESP that controls particulate emissions from our two biomass boilers. They indicated that it is possible a low-temperature SCR system installed after the ESP (to avoid poisoning the catalyst with boiler ash/particulate) could achieve a NOx reduction of 75 to 85%, but the system may only achieve 60% reduction in that location (not the 90% reduction that our four-factor analysis conservatively assumed). CECO provided a rough equipment cost estimate for installing an SCR system after the ESP on our Medford Mill's biomass boilers but we were not able to provide them with enough site-specific information in time for them to provide us with a cost for the Elgin Mill prior to the required submittal date for this response. However, CECO indicated to Medford that the expected equipment life was 20 years (not 30 years). We entered the lower control efficiency and the current prime rate into a revised cost spreadsheet based on the EPA equations used in our four-factor analysis and estimated a cost of \$9,993/ton based on the boilers' portion of the NOx PSEL if a reduction of 75% is achieved. The cost effectiveness would be more than \$10,000/ton if a lower reduction were achieved, which is possible according to the vendor. This cost is based on several assumptions and we do not consider installation of SCR on our two biomass boilers cost effective.

April 20, 2021

Boise Cascade Wood Products
Rhonda Smith
90 South 21st Avenue
Elgin, OR 97827-9614
RhondaSmith@bc.com

Reference: Boise Cascade, Elgin – Elgin Boiler NOx Control
CPL Systems, Inc Proposal No.: B301590

Dear Mrs. Smith,

At the time the boilers at Elgin were designed and installed, NOx and CO emissions were not a major design consideration. CO emissions were concerned mostly from the standpoint of combustion efficiency, so combustion effectiveness was improved to keep CO low and in doing so, adversely affected the NOx production. To keep CO low, fuel and combustion air were mixed rapidly, and combustion air was pre-heated to over 400°F to improve efficiency. Both techniques created high flame temperatures and NOx formation was prevalent.

Newer generation bio-mass boilers incorporate design changes to reduce NOx formation and keep CO emissions lower, however, the existing boilers would take major modifications to approach the new performance capabilities of bio-mass boilers today, even without end of pipe mitigation.

The following is a list of techniques that are used to reduce NOx on boiler systems today, however there are major challenges using these techniques due to cost of implementation and the cost to maintain and in most cases are difficult to implement on existing bio-mass boilers.

- SCR Systems: Selective Catalytic Reduction (SCR) is a common method of NOx reduction in boilers, just not bio-mass boilers. There are technical challenges when using selective catalytic reduction (SCR) for NOx emission reduction on bio-mass boilers. The challenges include managing gas stream temperature, gas stream cleanliness and catalyst effectiveness; therefore, SCR is determined to be technically infeasible on bio-mass boiler conversions.
- SNCR: Selective non-catalytic reduction (SNCR) is determined technically infeasible because the boiler has no locations with temperatures within the temperature window required for the reaction. SNCR requires temperature zones between 1550 and 2000°F. Additionally, boilers firing plywood trim, or dust from plywood can cause other environmental issues when the formaldehyde from the glues reacts with the ammonia.
- Staged Combustion: Implementing staged combustion technology presents numerous challenges, including injection port location limitations, hot spots on tubes, and possible damage to the unit's structural integrity. Many applications have been deemed infeasible because of the amount of modifications required to affect the results. In some cases, fuel bound nitrogen is a major contributor to the NOx formation, and staged combustion has little to no effect on NOx attenuation. Gasification in our opinion is a form of Staged Combustion.
- Flue Gas Recirculation: FGR when combined with staging combustion works to improve NOx reduction by slowing down the mixing of the volatilized fuel with the combustion air. Slower combustion reduces flame temperatures however, due to the size of the furnaces on older bio-mass boilers, FGR is not feasible. There is not enough room in the furnace to increase the time to affectively reduce the flame temperatures without adversely affecting CO emissions.

1.0 Background on Pollutant Formation

Nitrogen oxides (NO_x) are formed during combustion when nitrogen contained in the fuel and combustion air oxidize at high temperatures. Nitrogen is introduced to the system from either the fuel as fired (Fuel NO_x) and/or from the combustion air (Thermal NO_x). The NO_x is formed at combustion temperatures, and is not linear, as the temperature goes up, typically above 2200 °F, NO_x formation increases exponentially. Therefore, control of combustion temperature is critical to NO_x formation.

"Fuel NO_x" forms when the fuel bound nitrogen compounds are released from the fuel and are converted into nitrogen oxides during combustion. The amount of fuel bound nitrogen converted to fuel NO_x depends largely upon the fuel type (i.e. particle size, hardwood, softwood, moisture content and fuel age), nitrogen content of the fuel, air supply, combustion air temperature and boiler design. The reaction between elemental nitrogen and oxygen to form nitrogen oxides happens very rapidly. The primary methods for reducing fuel NO_x involves minimizing or slowing down the amount of oxygen (combustion air) that mixes with the fuel in the hottest part of the combustion zone.

"Thermal NO_x" is largely formed in the high-temperature portion of a flame, and post-flame combustion where temperatures are still high enough to drive the reaction. Again, temperature is the most important factor in the formation of thermal NO_x.

Nitrogen dioxide (NO₂) can then be formed in a reaction between the NO and oxygen in the combustion gases. In stationary source combustion, little of the NO is converted to NO₂ before being emitted unless the products of combustion can cool significantly before being emitted. As flue gasses cool, the NO continues to oxidize in the atmosphere. For this reason, all NO_x emissions from boilers are usually reported as NO₂.

2.0 Combustion Modification Technologies

The control technologies for combustion modification which are described below decreases NO_x emissions by reducing NO_x formation during the combustion process and before the flue gases are in contact with the boiler heat traps. This technique does not reduce NO_x emissions post combustion or prior to the flue gas being emitted to the atmosphere.

2.1 Flue Gas Recirculation (FGR)

Flue gas recirculation (FGR) involves recycling a portion of the exhaust gas back into the combustion zone where the oxygen molecules are not allowed to rapidly mix with the fuel. Additionally, the inert gases adsorb some of the heat generated by the flame, thus lowering peak flame temperature. The reduction of the peak flame temperature reduces the formation of thermal NO_x (reaction of N₂ and excess oxygen in the combustion air to form NO_x due to high temperatures of combustion).

FGR is effective in reducing Thermal NO_x, however in bio-mass boilers, FGR typically causes problems related to CO formation and ash carry-over because of incomplete combustion due to the increase in time required to fully combust the fuel. Most bio-mass boilers do not have the furnace volume to utilize this method.

2.2 Combustion Staging

Combustion Staging is performed in several methods. Each technique creates two combustion zones. Primary zone, where the majority of the combustion occurs, and the secondary zone where additional fuel and air are mixed again, and combustion is completed. This technique requires furnace length to produce the zones and affect the results.

Fuel staging is a technique where a portion of the total fuel input can be diverted to a second combustion zone downstream of the primary zone. Additionally, in a bio-mass boiler, another fuel source can be introduced into the second combustion zone, such as natural gas, propane, syngas, or bio-gas to work at reducing the NO formed in the primary combustion zone.

Combustion Staging techniques not unlike running the primary combustion zone with reduced oxygen produces CO or unburned fuel that is mixed with air in the secondary zone. Secondary air such as layered overfire air (OFA) reduces NO_x emissions by oxidizing the fuel in the secondary zone.

Air staging involves diverting a portion of the air required through separate ports so that partial combustion is carried out in the first stage with a lower air to fuel ratio than that of normal combustion, while secondary air is supplied to complete the combustion reaction in a subsequent combustion stage. Fuel-rich conditions in the first stage reduce fuel NO_x formation by limiting the amount of oxygen available to react with the fuel-bound nitrogen. Conditions in the secondary combustion zone result in lower peak temperatures and thus, lower NO_x emissions.

In a bio-mass boiler, the strategic use of OFA can provide some additional residence time in the furnace by creating a Z pattern for the flue gas in the furnace as the products of combustion rise off of the floor of the boiler. Use of high-pressure nozzles or jets at selective elevations in the furnace can push the products of combustion back and forth in the furnace. This technique is costly and uses a high-pressure fan to drive the air which consumes power over time.

Fluidized Recirculating Bed combustion is another means for staging combustion and reducing NO_x. Of course, this technique requires the design of a specialized furnace and bed system. Fitting a fluidized bed system to a stoker boiler is not practical.

2.3 Gasification

Gasification works by basically smoldering the fuel in a chamber without adequate combustion air creating a synergized gas. The gas is a low btu fuel that can be burned in a burner on a boiler. The low temperatures of the gasifier create little to no thermal NO_x. Combusting the low btu gas in a burner runs at very low temperatures and additionally oxidizes the NO_x that is created in the syn gas as well as creates very little thermal NO_x from final combustion. The system is complex and maintenance intensive.

2.4 Low NO_x Burners (LNB)

Low NO_x Burners utilize several methods of reducing NO_x, (i.e. fuel staging, air staging, FGR, Fuel Induced FGR, bio-fuels, very low excess air) The Low NO_x burners use the techniques to reduce peak flame temperatures to control the formation of NO_x.

The boilers can be fitted with low NO_x burners, however, the boilers would no longer be allowed to run on bio-mass in order to achieve the desired reductions to 30 ppm NO_x. In order to go lower NO_x than 30 ppm, the boilers would have to be raised and burners fired from the floor. This is not a good solution.

2.5 Low Excess Air (LEA)

LEA involves reducing the amount of excess combustion air to near-stoichiometric levels and reducing flame temperature, therefore decreasing thermal NO_x formation. In most cases, bio-mass boilers will not run in this technique due to poor mixing of fuel and combustion air. This technique requires precise metering of fuel, precise fuel quality, moisture and size and precise positioning of fuel from the stoker.

3.0 Post-Combustion Controls

Post-combustion or end of pipe control technologies detailed below include Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). Each technique works to convert the NO_x to N₂ and H₂O by spraying a reagent into the products of combustion.

3.1 Selective Catalytic Reduction (SCR)

The SCR technique involves injecting a reagent (ammonia or urea) into post combustion flue gas then passing the gas through a catalyst bed where NO_x is converted to N₂ and H₂O. The temperature target zone for the flue gas is in the range of 550 to 800 °F.

For SCR systems to work in bio-mass applications, the system must be installed at the boiler outlet where flue gas is between 650 and 750°F. Of course, this is the dirtiest part of the flue gas stream. The flue gas must pass through high efficiency cyclones, then high temperature bag-houses or a high temperature Electrostatic Precipitator to remove the ash and char before the flue gas can enter the catalyst. This minimizes fouling of the catalyst. Online cleaning systems use lances to clean the face of the catalyst. This technique is considered a Hot Side SCR. The combustion air heater and economizer must be moved downstream of the SCR to maintain boiler performance.

Cold Side SCR technologies require flue gas temperatures above 550°F. In most cases, the technique won't work without some form of flue gas re-heat to increase the temperature of the flue gas back up over 550°F. Low temperature catalyst has not been used in this application due to the particulate loading even post particulate treatment. Most of the good performing bio-mass boilers run at flue gas temperatures below 450°F. The boilers at Elgin operate on average of 414 degF.

Regenerative SCR (RSCR) systems provide a means of Cold Side treatment where the flue gas has been treated for particulate removal by cyclones and bag-house or ESP. The reagent is sprayed into the flue gas and then enters a heated ceramic chamber that re-heats the flue gas. After the chamber, the flue gas enters the catalyst and the NO_x is treated and converted to N₂ and H₂O. The flue gas is then passed through a chamber with a burner that heats the flue gas and passes the heated gas over the ceramic chamber that is used to re-heat the untreated flue gas. The technique of regenerated flue gas heating reduces the amount of fuel gas required to reheat the untreated flue gas.

3.2 Selective Non-Catalytic Reduction (SNCR)

SNCR is an exhaust gas treatment process in which urea or ammonia is injected into the hot zone of products of combustion. High temperatures, between 1,600 and 2,100°F, promote the reaction between urea or ammonia and NO_x to form N₂ and water without the use of a catalyst. The effectiveness of SNCR systems depends on the inlet NO_x concentration, temperature, mixing, residence time, reagent-to-NO_x ratio, and fuel sulfur content.

Outside of the design temperature window, the emissions are adversely affected. If the temperatures are too high, then the reagent may be oxidized, causing additional NO_x emissions. If the temperatures are too low, then the reaction between the reagent and NO_x is slowed, and emissions of the reagent will be present in the flue gas.

4.0 Retrofitting Options

Applicable NO_x control technologies are identified based on:

- Published information from research, technical experts, and OEMs
- Searching EPA databases
- A review of recently issued permits for similar biomass boilers
- Expertise in the field of NO_x reduction and combustion techniques

The existing boilers at Elgin are 60,000 pph saturated steam Keeler Boilers fitted with Detroit Stoker water cooled grates. The system has air swept fuel spouts for fuel distribution with three layers of over-fire air. The combustion controls are operated manually for the most part for setting fuel to air ratios and draft. The two boilers are piped into a single ESP for particulate removal. Based on the emissions data provided, the NO_x levels are well within the expected range for the boilers. 125 ppm is typical for this design firing on good bio-mass fuels. CO emissions are good as well in the 250 to 400 ppm range. This is an indication that the boiler is in good condition and not experiencing excessive fuel bound nitrogen.

Typically, minimal thermal NO_x is formed in wood-fired spreader stoker boilers due to the high moisture content of the wood, and the spreader stoker firing configuration. Even with high combustion air temperatures, NO_x formation is low in these boilers. The fuel as fired appears to be a low percentage of plywood trim or plywood dust. Each of which will contribute to increased NO_x formation. It is not practical to consider combustion modification technologies in these units that are aimed at

reducing thermal NO_x formation. FGR, OFA, or additional combustion staging are not considered as a viable solution to create a step change in the NO_x emissions. Traditional combustion modifications that are used in Low NO_x or Low Emissions burners will not apply in this case.

These boilers incorporated a minimal overfire air configuration. The OFA system on these boilers were originally installed to improve particulate emissions by allowing lower under grate air flows. The technique inherently reduces NO_x through staged combustion technology. Overfire air systems are commonly employed in spreader stoker boilers.

Boiler operations and consistency can be improved by implementation of a combustion control system. The system would work to reduce excess air, improve staging, and provide better fuel to combustion air ratio control. Unfortunately, a significant reduction in NO_x is not a practical expectation.

In stoker fired bio-mass boilers, FGR can be fitted on the fuel stokers as distribution air in order to minimize the NO_x formed at the fuel feed throats. In these boilers prompt NO_x forms at the fuel feeder throats due to high peak flame temperatures at this point. Of course, the dryer, the fuel, and the more fines that are part of the fuel, the more NO_x is formed at the stoker throat and therefore the higher the percentage of NO_x is reduced from this technique. The Elgin boiler is already running good numbers for this type of boiler and no more than 5 to 7% reduction can be expected and may even be less.

4.1 Post-Combustion Controls

4.1.1 Selective Catalytic Reduction (SCR)

High PM concentrations upstream of the PM control equipment (Hot-side/High-dust) impedes catalyst effectiveness and results in deactivation or poisoning of the catalyst, which requires downtime to clean and/or replace the catalyst and loss of NO_x reduction performance. In biomass boilers, plugging and fouling of the catalyst occurs due to large amounts of fly ash generated by the biomass. Relocating of the air pre-heater is required to implement this technique.

The installation of an SCR downstream of the PM control equipment (Cold-side/Tail- end SCR) renders the gas stream too cold for an effective reaction with the catalyst to reduce NO_x.

Implementing an SCR on these hog fuel boilers poses several technical challenges. First, consideration should be given to the footprint; size constraints makes retrofitting an SCR system near the boiler near impossible. Second, boilers' temperature profiles are not appropriate for SCR, and the SCR system pressure drop requirements may create sizing concerns related to existing boiler fans. Finally, the location of the SCR is critical. Installing an SCR post the ESP is the only solution without major modifications to the boilers. The flue gas temperature is too low exiting the existing ESP.

The desired minimum temperature for the SCR in this application to achieve 70% control is 575°F. The annual average exhaust temperature of two Keelers after the ESP is 414°F. The exhaust temperatures of the two boilers are well below the range of operation of the SCR system, higher temperatures are needed for optimum control efficiency for the SCR application.

In order to raise the flue gas to temperatures high enough for the SCRs to work, over 11.0 MMBtu/hr. of natural gas would be used to re-heat the flue gas just to get the SCR system to work. Over 15 lbs. per hour of anhydrous ammonia is required, about 250 electrical horsepower is required and the boiler flue gas CO₂ flow would increase by 5600 tons per year.

Implementing individual SCRs on each boiler is not practical due to the following. To install an SCR on the boilers, the air heater would have to be removed from the back of the boiler, the primary dust collector moved to the back of the boiler and resized for high temperature flue gas. A new high temperature ESP would be installed behind the dust collector to remove the particulate prior to the SCR. The SCR and injection grid would be installed behind the ESP. After the SCR, the air heater would be reinstalled with all new combustion air and draft fans.

The option in this case is the Regenerative type SCR whereby which a re-heat chamber is provided for the flue gas existing the existing ESP. The technique is described above. The challenge again is real estate to implement the system and then costs. The actual fuel consumption provided to the re-heat will be roughly 5 to 6 MMBtu/hr. Maintenance costs to maintain and clean the catalyst are a major consideration. CO₂ increases by 2700 tons per year as well as electrical hp increases by 300 or more horsepower.

In an RSCR system, the regenerative heating reduces the required heat input; however, this reheating of the flue gas still represents a significant amount of auxiliary fuel that would be necessary for successful operation.

Moreover, it is not considered an available technique, as RSCR has not been demonstrated on load-following boilers. As noted above, locating the SCR in a higher temperature region (Hot-side/High-Dust SCR) to avoid the issue with use of auxiliary fuel results in catalyst exposure to high particulate emissions from hog fuel combustion that damages the catalyst.

The technical difficulties described above apply generally to biomass boilers. Advanced technologies and auxiliary heating of the tail-end flue gas have been developed recently in an attempt to overcome these difficulties. However, the wide load swings experienced by plywood mill boilers result in unstable exhaust temperatures and would make it particularly difficult to control the flue gas temperature and reagent injection rate needed to ensure appropriate NO_x reductions while avoiding excessive ammonia slip. For these reasons, SCR technology has not been successfully demonstrated for a load-following spreader-stoker boiler with load swings comparable.

4.1.2 Selective Non-Catalytic Reduction (SNCR)

With the recent advancements in SNCR technology, Implementing SNCR on industrial load-following hog fuel boilers continues to pose several technical challenges. Newer techniques include setting up multiple injection grids and the use of NO_x Continuous Emissions Monitoring Systems (CEMS)-based feedback loops to control flow to the individual grids. Additionally, with an SNCR system, the injection of the reagent must be applied in a narrow temperature window for the reduction reaction to successfully complete. As mentioned above, high temperatures, normally between 1,600 and 2,100 °F, promote the reaction between urea or ammonia and NO_x to form N₂ and water.

In the load-following boiler, the region of the boiler where the optimal temperature range is present would vary depending on the firing rate, making it very difficult to control the SNCR reaction temperature. With years of practice and modeling, the boiler grate is the only location that reaches even the low end of this temperature range. Therefore, no locations exist within the boilers with high enough temperature for SNCR to be technically feasible.

Another consideration preventing proper implementation of SNCR technology in load-following biomass boilers is inadequate reagent dispersion in the injection region. This leads to significant amounts of unreacted ammonia exhausted to the atmosphere (i.e., large ammonia slip). To our knowledge, the SNCR systems that have been installed on bio-mass boilers have been decommissioned. In some cases, in plywood mills that do burn ply trim or dust, the reagent reacts with the formaldehyde causing bigger environmental problems.

5.0 Budget Estimates

The following chart is a budget estimate of applications. In some cases, the costs were pulled from actual completed projects.

Recommended Modifications 5 to 7 % reduction in average NOx		
FGR and OFA Modifications Per Boiler	x2	\$ 250,000.00
Combustion Controls Per Boiler per Boiler	x2	\$ 620,000.00
Total for both boilers		\$ 1,740,000.00

6.0 Conclusion

NOx emissions from the Keeler Boilers are largely un-controlled, however, by original design, based on current loading, and along with using good operating practices, the emissions are what is expected for this type of installation.

The NOx emissions are typical, and more on the lower side based on many boilers we have worked on.

The use of a computerized control system to optimize the air and fuel feed rates along with strategic use of FGR on the fuel feeders can help with a small reduction of NOx. The boilers are already fitted with OFA, and good particulate controls. It leaves us to state that all discussed NOx control technologies are determined to be technically or economically infeasible.

April 20, 2021

Michael Orman
Oregon Department of Environmental Quality
700 NE Multnomah Street, Suite 600
Portland, OR 97232

Re: Boise Cascade Wood Products, LLC – Elgin Complex
Regional Haze Program, Additional Information
Title V Facility 31-0006

Mr. Orman,

The Elgin Complex (Facility) received a Preliminary Determination of Cost Effective Controls letter from the Oregon Department of Environmental Quality (DEQ) on January 21, 2021. Based on the Facility submitted June 2020 Four Factor Analysis and August 18, 2020 Supplemental Information, the DEQ concluded installation of a Selective Catalytic Reaction (SCR) control device for NO_x would likely be required for the Facility's Boilers 1 and 2. This letter summarizes information obtained by the Facility to evaluate the effectiveness of SCR for control of NO_x from their wood-fired boilers.

The Facility's June 2020 Four-Factor Analysis identified several technical challenges and uncertainties associated with use of SCR. These included:

- SCR is not identified in the EPA RBLC database as an existing control technology deployed on biomass-fired industrial boilers.
- The temperatures of boiler flue-gas exiting the Facility's Dry Electrostatic Precipitator (DESP) are generally below the minimum SCR operating temperature and well below the optimum operating temperatures for catalyzed reactions.
- Flue-gas reheating would be required for effective SCR operation, which would result in additional energy usage and GHG emissions.
- The presence of alkali metals and other constituents found in wood could poison catalysts.
- There is risk of ammonia slip, oxidation of CO to CO₂, and formation of sulfuric acid mist emissions associated with injection of ammonia.

In addition to these concerns, the Facility estimated the annualized cost per ton of implementing SCR would be \$9,993/ton and ultimately screened SCR from further consideration based on cost effectiveness.

Since receiving the DEQ's January letter, the Facility has worked diligently to gather additional information to determine appropriate controls for NOx reduction.

Maul Foster Alongi was consulted to evaluate technical feasibility for installing SCR on the Facility's boiler system. Their findings are attached in a Technical Memorandum and a brief summary of their findings is presented below:

- There are no applications of SCR controls on a wood-fired boiler that are comparable in size to Facility boilers.
- SCR controls have not been implemented on load-following boilers.
- SCR controls have not been implemented on primarily bark-fired boilers.
- SCR controls have not been implemented on any wood-fired boilers in Oregon.
- Oregon soils often have higher concentrations of metals that are catalyst poisons than other locations where SCR has been implemented. These metals are accumulated in the wood burned in the boilers
- The average flue-gas temperature following the Facility's DESP is less than the typical operating temperature for SCR and well below the optimal temperature range for catalytic reduction.
- For the reasons described above, SCR was determined to not be technically feasible for the Facility's wood-fired boilers.

CPL Combustion & Control Systems (CPL) and Jansen Combustion & Boiler Technologies, Inc. (Jansen) were brought onsite in April 2021 to evaluate the Facility's boiler system and identify possible NOx reduction controls. As discussed in their attached report, CPL determined SCR was not technically feasible for control of NOx from the Facility's boiler system and concluded overfire air (OFA) and combustion controls were technically feasible, but they estimated only a potential 5 to 7% reduction in average NOx with implementation of OFA and combustion controls. Based on their cost estimate of \$1,740,000 to implement, the cost per ton reduction using PSEL for NOx would be roughly \$150,000/ton, therefore it is not considered to be economically feasible. Extensive modeling of the system would be required in order to determine actual reduction of NOx achievable and to obtain a performance guarantee for implementation of OFA and combustion controls. Jansen is in the process of reviewing Facility data and drawings to complete a proposal for recommended boiler improvements to reduce boiler NOx emissions, with a tentative completion date of early May. Their preliminary conclusion regarding SCR on Elgin's Boiler System is that it was technically infeasible and possible approaches included combustion control, similar to controls CPL's evaluated. Typical achievable maximum range for NOx reduction for these controls is 0 – 30 %. The achievable range for the Elgin's Boilers is in the lower range, based on CPL's evaluation and configuration of the boiler system. Even if the Elgin Boilers were capable of achieving the maximum reduction using combustion controls at 30%, the reduction would be roughly \$35,000/ton, based on CPL's cost estimate.

In addition to the technical details described above, the Facility and corporate safety have expressed a strong preference against storage and transfer of anhydrous ammonia, required for SCR, due to risk to employees and the community. The Facility does not have the necessary equipment or training for maintaining transfer and storage

systems or responding to leaks of this hazardous material. Storing and handling anhydrous ammonia on site could also require the Elgin Facility to be subject to the Process Safety Management (PSM) and Risk Management Plan (RMP) programs.

Based on the information summarized above and the provided attachments, the Facility has concluded SCR is technically infeasible for NOx control of emissions from Boilers 1 and 2. In addition the Facility has tentatively concluded, pending confirmation from Jansen, that implementation of OFA and combustion controls is financially infeasible. No other NOx control options have been identified as potentially feasible for further review.

Please call Rhonda Smith at 541-437-2207 if you have any questions regarding this submittal.

Sincerely,



Dale Treib
Production Manager

Cc: via email with Attachments

J Westersund, D Welch, K Williams, M Bailey, M Orman – ODEQ
R Smith, T Riecke, R Strader, J Stearns - BCWP

Attachments:

1. Maul Foster Alongi, Technical Memorandum: Selective Catalytic Reduction (SCR) Control Evaluation, April 19, 2021
2. CPL Combustion & Control Systems, Elgin Boiler NOx Control Proposal, April 19, 2021



MEMORANDUM

To: Ms. Rhonda Smith Date: April 19, 2021
From: Maul Foster & Alongi, Inc. Project No.: 1270.03.04
RE: Selective Catalytic Reduction (SCR) Control Evaluation—Boise Cascade Elgin Facility

Maul Foster & Alongi, Inc. (MFA) was retained by Boise Cascade Wood Products, LLC (Boise) to conduct a technical evaluation of SCR for the wood-fired boilers at the Boise facility located at 90 South 21st Street, Elgin, Oregon 97827 (the “facility”). The focus of the evaluation is to assess the feasibility of SCR to reduce nitrogen oxide (NO_x) emissions from the facility boilers.

BOILER INFORMATION AND PARAMETERS

The facility operates two wood-fired, spreader-stoker boilers that supply process steam to support the plywood manufacturing operations. Each boiler has a maximum heat input capacity of 72 million British thermal units per hour (MMBtu/hr) and a rated steam production capacity of 60,000 pounds per hour. The boilers combust hogged wood that consists primarily of bark. On average, bark represents 90 percent of the total hogged fuel used, with the balance comprised of stem wood (e.g. clean wood chips, sawdust, plytrim, etc.).

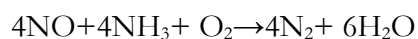
Exhaust from each boiler is routed to a dedicated multiclone, then to an induced draft fan, and finally a common header where exhaust from the two boilers combine prior to final particulate emissions control using a dry electrostatic precipitator (DESP). Select exhaust parameters for the boilers at the combined DESP exhaust stack are shown in Table 1.

Table 1. Boiler Exhaust Parameters

Parameter	Value
Exhaust Flow Rate ¹	106,663 acfm
Exhaust Temperature ²	414°F
Exhaust Moisture Content ¹	16%
NOTES: acfm = actual cubic feet per minute 1. Data based on results of performance source test conducted in November 2019. 2. Average DESP exhaust temperature from February 2020 to February 2021.	

SCR CONTROL FOR NO_x REDUCTION

SCR reduces NO_x emissions with ammonia in the presence of a catalyst. The major advantages of SCR technology compared to selective non-catalytic reduction are the higher potential control efficiency (70% to 90%) and the lower temperatures at which the reaction can take place (480°F to 800°F¹, depending on the catalyst selected). The optimal temperature range for catalytic reduction is 650°F to 850°F². 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. The primary reactions that take place in the presence of the catalyst are:



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 binding, plugging, and fouling 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. The impacts on catalyst performance due to manganese, another metal found in higher quantities in wood than fossil fuels, are unproven³. Other naturally occurring catalyst poisons found in wood are phosphorus and arsenic.

¹ OAQPS 7th Edition. June 2019. *Chapter 2 Selective Catalytic Reduction*. https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf (Section 2.2.2).

² OAQPS 7th Edition. June 2019. *Chapter 2 Selective Catalytic Reduction*. https://www.epa.gov/sites/production/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf (Figure 2.2).

³ National Council for Air and Stream Improvement, Inc. (NCASI). 2019. *An Update on NO_x Control Limits and Technologies for Forest Products Industry Boilers, Kraft Recovery Furnaces, and Lime Kilns*. Technical Bulletin No. 1051.

In order to prevent the plugging, blinding, and/or poisoning of the SCR catalyst, it is necessary to first remove particulate from the exhaust gases. It is not considered technically feasible to place an SCR unit upstream of the particulate control device in a wood-fired boiler application due to the potential for decreasing the useful life of the catalyst and decreasing the control efficiency, which can happen relatively quickly. In addition to catalyst deactivation via poisoning from contaminants present in the exhaust gas, ash from wood-fired boiler exhaust is extremely abrasive and can further damage catalyst by “sandblasting” the active pore sites of the catalyst, resulting in a decrease of the number of sites available for NO_x reduction.

Use of SCR on a wood-fired boiler application requires a high temperature particulate control device so that the downstream temperature is still in the range of 480°F to 800°F, which is necessary for the reduction of NO_x in the presence of the catalyst. The SCR unit may, in certain circumstances, be located downstream of the particulate controls, after most of the ash and contaminants have been removed from the exhaust. This SCR configuration requires that temperatures downstream of the particulate controls are still within the effective temperature range for NO_x reduction by catalytic reaction.

SCR IMPLEMENTATION AND TECHNICAL FEASIBILITY

MFA conducted a search of the Environmental Protection Agency (EPA) “RACT, BACT and LAER Clearinghouse”, commonly referred to as the RBLC. This is an EPA database populated with RACT, BACT and LAER determinations across the United States. The search was conducted to identify implementation of SCR control systems on biomass combustion units, and the following search criteria was used:

- Permitting dates: January 1, 2007 through April 7, 2021
- Process types: Biomass fuel combustion (11.120, 12.120, and 13.120)
- Pollutant: NO_x

Note that the default search criteria for querying the RBLC is for the past 10 years. MFA is aware of SCR control systems implemented for biomass combustion units prior to 2010; therefore, to provide a more comprehensive review, MFA expanded the query beyond the default determination date. RBLC entries that identified a control device other than SCR as the control method were excluded from further analysis. The search results are presented in Table 2 in Attachment A, along with select data on each unit from the RBLC database. MFA assigned numbers to each RBLC entry that correspond to the discussion presented below.

Units 1, 2, 4, 5, 8, and 9 in the RBLC database were not constructed and therefore do not demonstrate practical application of SCR control technology. Units 3 and 11 do not combust wood and so are not representative of SCR control on wood-fired boilers. The remaining RBLC entries are Units 6, 7, and 10, which require additional evaluation. Note that Units 6, 7, and 10 implemented SCR control on newly constructed combustion units rather than a retrofit installation on an existing boiler.

The heat input capacities of the units range from 693 to 1,358 MMBtu/hr. Even the smallest unit is over nine times larger than the capacity of the facility boilers. Additionally, Units 6, 7, and 10 are all utility boilers, which typically operate at steady-state, base load conditions. This is fundamentally different than operation of the facility boilers, which operate to supply process steam to the manufacturing operations. As a result, boiler operating loads follow the steam demand at the facility. Therefore, the units should not be considered for comparison to the facility boilers.

Another significant difference between the facility boilers and Units 6, 7, and 10 is the type of fuel combusted. Unit 6 burns only clean wood chips, which are substantially different than the majority bark fuel used by the facility. Specifically, bark fuel presents additional challenges with regard to catalyst deactivation via poisoning than wood chips. More details on the differences in bark and stem wood (e.g. clean chips) is provided in subsequent sections. Based on the description of fuels used in the RBLC database and permits, only Units 7 and 10 may potentially be using bark as part of the fuel mix in the form of logging residuals. However, it is unlikely, based on the available information, that the units combust bark in quantities that approach the 90% bark fuel mix that is typical of the facility boilers. Therefore, the units are not comparable to the facility boilers based on the fuels combusted.

Table 3 presents the concentrations of select metals in wood fuels based on information from the National Council for Air and Stream Improvement (NCASI). These data clearly show that bark fuel has higher concentrations of metals than non-bark fuel (i.e. stem wood). As metals present particular concern for catalyst deactivation, this suggests that biomass combustion where bark comprises the majority of the fuel mix may not be suited for SCR control technology.

Table 3. Metal Contaminant Concentrations in Wood Fuels

Contaminant	Mean Concentration (ppm) ¹	
	Bark	Stem Wood
Arsenic	1.56	0.419
Lead	2.59	0.550
Manganese	167	32.5
Nickel	3.3	0.700
Selenium	0.593	0.650
Zinc	19.2	4.36
NOTES: 1. NCASI Handbook of Chemical-Specific Information for SARA Section 313 For R Reporting – Pulp and Paper Facilities – RY2018 (updated May 2019).		

Additional contaminants may also be present in bark fuel due to log harvesting, log stacking and storage, and bark handling activities, where contact with soils can result in foreign particles becoming entrained in the fuel prior to introduction to the combustion unit. Entrained soil represents an additional contaminant loading that is unique to bark fuels but is not expected to be applicable to units burning clean wood chips and other stem wood.

The fuel data presented in Table 3 are based on composite values for facilities located throughout the United States. Metals and other minerals present in biomass are the result of uptake from the soil. As a result, the concentration of metals and minerals in the soil can directly affect the concentration of metals and minerals in the biomass. The figures in Attachment B present United States Geological Survey data on soil concentrations for select metals across the United States. The concentration of these metals in Oregon, which is the primary source of logs and fuel for the facility, are higher than other regions of the country where SCR controls have been implemented on biomass combustion units. Note that there are no SCR controls in use on wood-fired boilers in Oregon, and as stated above, no SCR controls on predominantly bark burning combustion units in the United States.

The facility boilers are equipped with a DESP for final emissions control. As no control devices are 100% effective, particulate matter in the form of fly ash is still emitted. Table 4 presents typical concentrations of metals and other minerals in wood combustion ashes.

Table 4. Typical Metal Contaminant Concentrations in Wood Ash

Contaminant	Concentration (ppm)
Arsenic ¹	6.67
Lead ¹	50.1
Manganese ²	4,370
Nickel ¹	45.7
Phosphorus ¹	6,365
Potassium ¹	30,000
Selenium ¹	4.36
Sodium ¹	2,377
Zinc ¹	303.5
NOTES: 1. Average of results from Boise Medford mill ash analyses performed in June 2000 and August 2002. 2. NCASI Handbook of Chemical-Specific Information for SARA Section 313 For R Reporting – Pulp and Paper Facilities – RY2018 (updated May 2019).	

Note that known catalyst poisons, including arsenic, phosphorus, potassium and sodium, are present in elevated concentrations in wood combustion ashes. These contaminants are present in the treated exhaust gases (i.e., post- DESP control) and therefore can potentially deactivate SCR catalyst and render the NO_x control system ineffective.

As shown in Table 1, the exhaust gas temperature at the DESP exhaust is 414°F. This temperature is below the typical SCR operating range and is well below the range optimal for catalytic reduction (650°F to 850°F). The exhaust conditions at the DESP outlet of the facility boilers is significantly different than utility boilers where SCR control systems have been installed. Specifically, utility boilers

are typically operated as base-load units where steam loads and resulting exhaust parameters are more consistent. There are no available data demonstrating that SCR is a proven, effective control technology for load-following boiler applications such as the facility boilers. In addition, due to the contaminants present in the exhaust gas after DESP control, SCR is not a technically feasible technology.

SUMMARY

While SCR control systems have been implemented on wood-fired boilers, as evidenced by the RBLC database query, none of the installations were retrofit applications or for units of a comparable size to the facility boilers. Nor are operating conditions for the RBLC installations comparable to the facility boilers since those units are electricity generating units rather than load-following units that solely supply process steam to support manufacturing operations. There are significant differences in fuels used and none of the RBLC applications demonstrate feasibility for primarily bark-fired boilers. Furthermore, no wood-fired boilers in Oregon have implemented SCR where the metal concentrations in the regional soil may present additional challenges with regard to wood fuels and the resulting contaminant loading and catalyst poisoning. The issues with catalyst plugging and deactivation are well-documented for wood fuels, and the bark fuel in use at the facility will have significantly higher concentrations of catalyst poisons than stem wood, as shown in Table 3. Despite having an existing particulate control, these contaminants are known to be present in combustion ashes in the post-control exhaust gas, so it is not clear that SCR would be feasible downstream of the DESP. Additionally, the average temperature of the exhaust gas downstream of the DESP is less than the typical operating temperature range of SCR and is well below the optimal temperature range for catalytic reduction.

In summary, there are no identified applications of SCR controls on a wood-fired boiler that is comparable in size to the facility boilers. SCR controls have not been implemented on load-following boilers. And no application of SCR controls for primarily bark-fired boilers have been identified. Therefore, SCR is not a technically feasible control technology with proven applicability for the facility boilers.

ATTACHMENT A

TABLE



Table 2
RBLC Search Summary - Biomass Combustion Units with SCR Control for NOx Emissions ⁽¹⁾
Boise Cascade Wood Products—Medford, Oregon

Unit	Facility	Permit Type ^(a)	Unit Constructed? (Yes/No)	Process Description	Boiler Input		Primary Fuel	Secondary Fuel	Control Device	Percent Control Efficiency	Location
					Capacity	(units)					
1	SUN BIO MATERIAL COMPANY	A	No	Power Boiler at a kraft paper mill	1,200	(MMBtu/hr)	Biomass residuals from the paper mill.	Natural gas and dewatered sludge from the wastewater treatment plant	Selective Catalytic Reduction	--	Arkansas
2	MONTVILLE POWER LLC	D	No	42 MW Biomass utility boiler	600	(MMBtu/hr)	Clean wood	Natural gas or ULS distillate for startup and peaking.	Regenerative SCR	70	Connecticut
3	ABENGOA BIOENERGY BIOMASS OF KANSAS (ABBK)	A	Yes	Biomass cogeneration boiler at a biomass-to-energy production facility	500	(MMBtu/hr)	Biomass, including wheat straw, sorghum stubble, corn stover, switchgrass and liquid biomass residuals	Natural gas for startup	Selective Catalytic Reduction System (SCR) and an over-fire system (OFA)	--	Kansas
4	CONCORD STEAM CORPORATION	A	No	19.7 MW biomass power plant; stoker-type boiler	305	(MMBtu/hr)	Wood chips	Natural gas for startup	Selective Catalytic Reduction	70	New Hampshire
5	CLEAN POWER BERLIN LLC	A	No	29 MW biomass power plant/cogeneration plant; Wellons close coupled gasifier unit	41	(tons/hr)	Wood Chips	Natural gas for startup	Selective Catalytic Reduction (SCR) with Staged Combustion	70	New Hampshire
6	BURGESS BIOPOWER BERLIN STATION LLC	A	Yes	75 MW biomass electrical generating facility; refurbished Babcock & Wilcox Bubbling Fluidized Bed boiler	1,013	(MMBtu/hr)	Wood Chips	No. 2 fuel oil backup	SCR (Cold Side of Baghouse) with Ammonia Injection	--	New Hampshire
7	LUFKIN GENERATING PLANT; ASPEN POWER LLC	A	Yes	45 MW Wood-fired boiler	693	(MMBtu/hr)	Wood, primarily logging or lumber mill residue	--	Selective Catalytic Reduction	--	Texas
8	BEAVER WOOD ENERGY FAIR HAVEN	A	No	34 MW Wood-fired utility cogeneration boiler at a wood pellet manufacturing facility	482	(MMBtu/hr)	Wood	--	Good combustion control and a Multi Pollutant Catalytic Reactor (NOx SCR)	--	Vermont
9	NORTH SPRINGFIELD SUSTAINABLE ENERGY PROJECT	A	No	37 MW Wood-fired electric generating unit	464	(MMBtu/hr)	Wood	--	Bubbling fluidized bed boiler design and SCR	--	Vermont
10	GAINESVILLE RENEWABLE ENERGY CENTER	B	Yes	100 MW electric power plant utilizing a bubbling fluidized bed biomass boiler	1,358	(MMBtu/hr)	Clean woody biomass	Natural gas for startup	Efficient Combustion. SCR system	--	Florida
11	TATE & LYLE INGREDIENTS AMERICAS, INC.	B	Yes	Two fiber-fired boilers and germ dryers at a corn wet mill	200	(MMBtu/hr)	Corn Fiber	--	Selective Catalytic Reduction	--	Iowa

NOTES:

RBLC = EPA RACT/BACT/LAER Clearinghouse

SCR = selective catalytic reduction.

SNCR = selective non-catalytic reduction.

(a) Permit Types as identified in the RBLC and based on the descriptions below. Sources that were identified as "A" for new construction were excluded.

A = new facility/greenfield

B = Add new process to existing facility

C = Modify process are existing facility

D = Both B & C

U = Unspecified

REFERENCES:

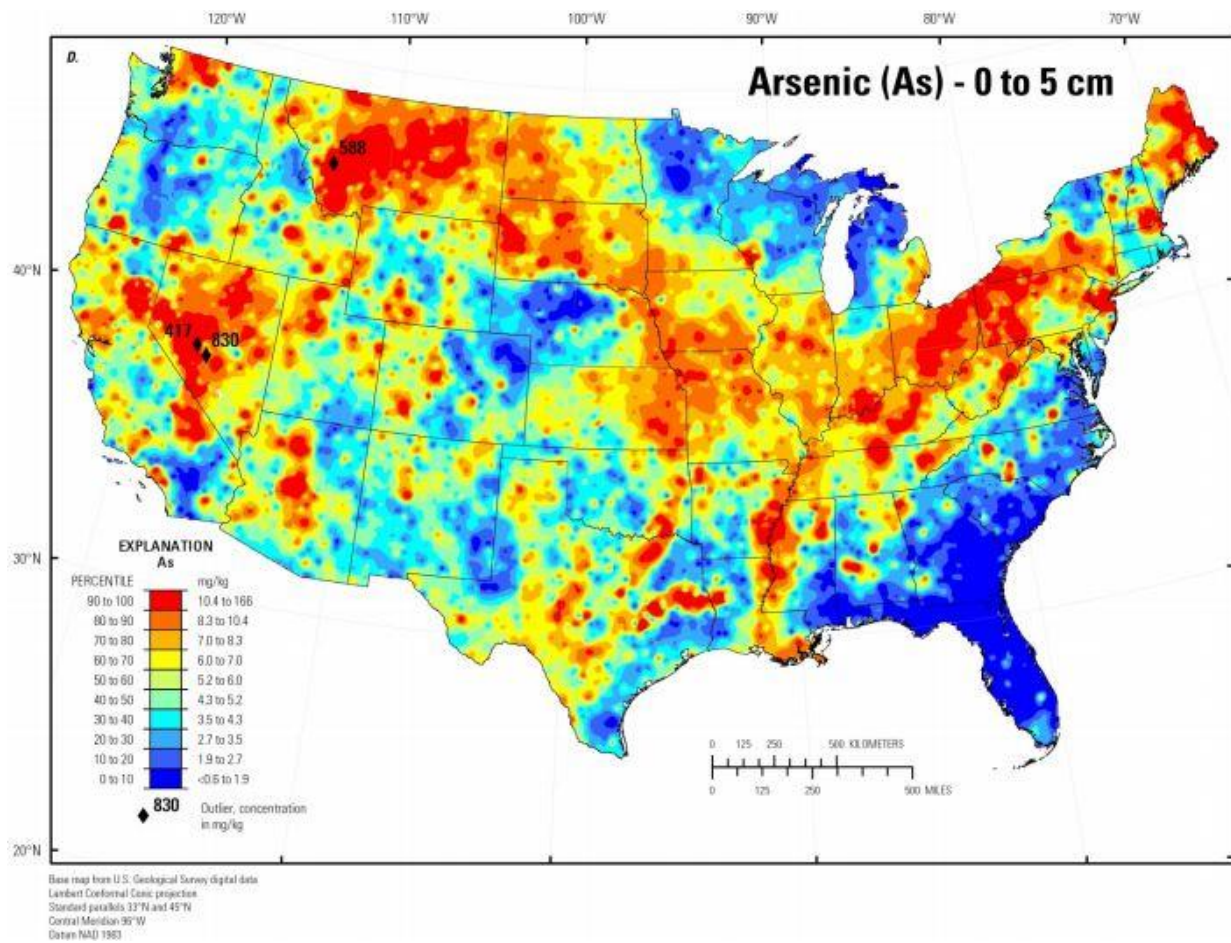
(1) All search results from RACT/BACT/LAER Clearinghouse. Searches were conducted for permitting dates for January 1, 2007 through April 7, 2021 and biomass fuel combustion process types (i.e. 11.120, 12.120, and 13.120).

ATTACHMENT B

FIGURES

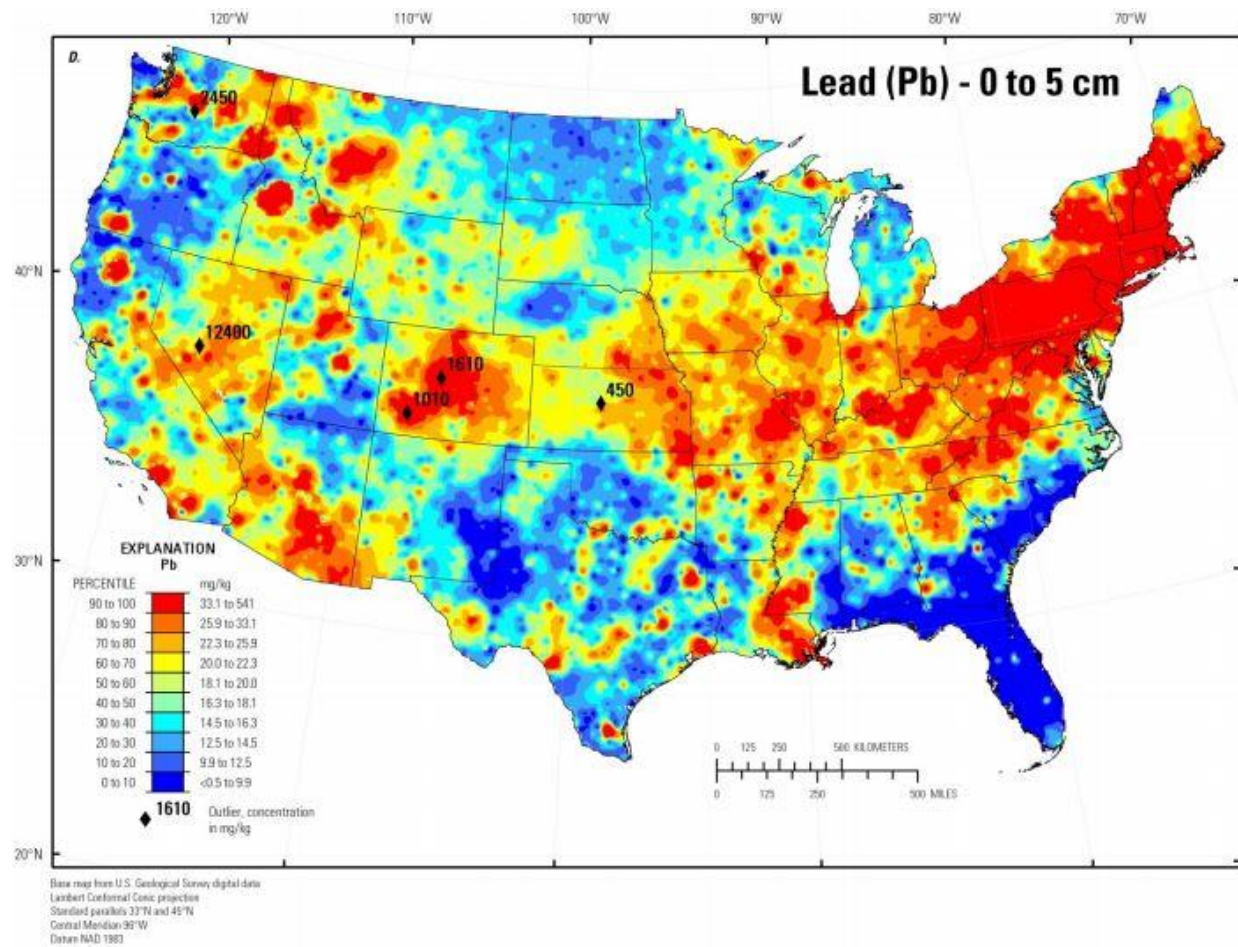


Figure 1. USGS Map of Arsenic Concentrations in Surface Soil



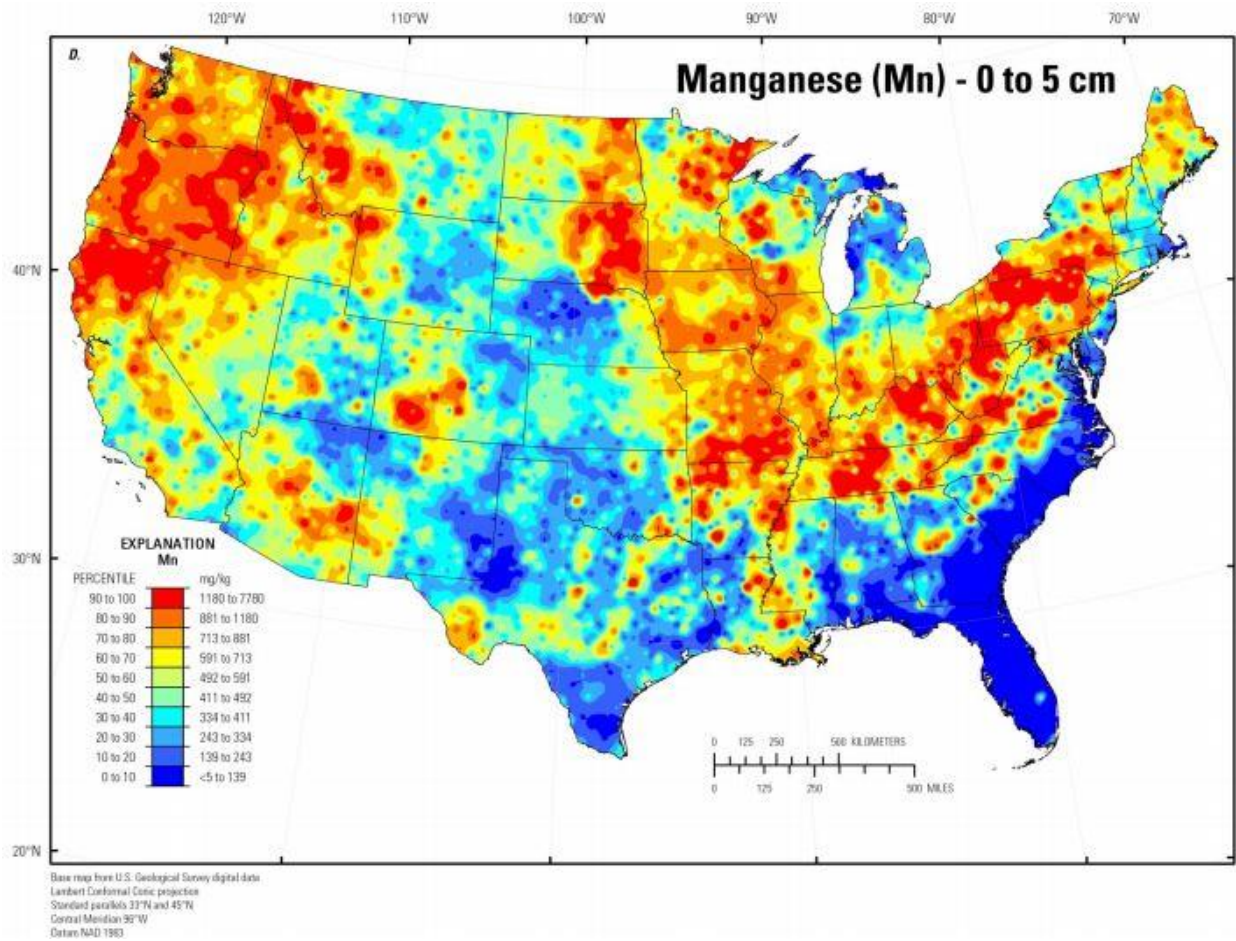
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Figure 2. USGS Map of Lead Concentrations in Surface Soil



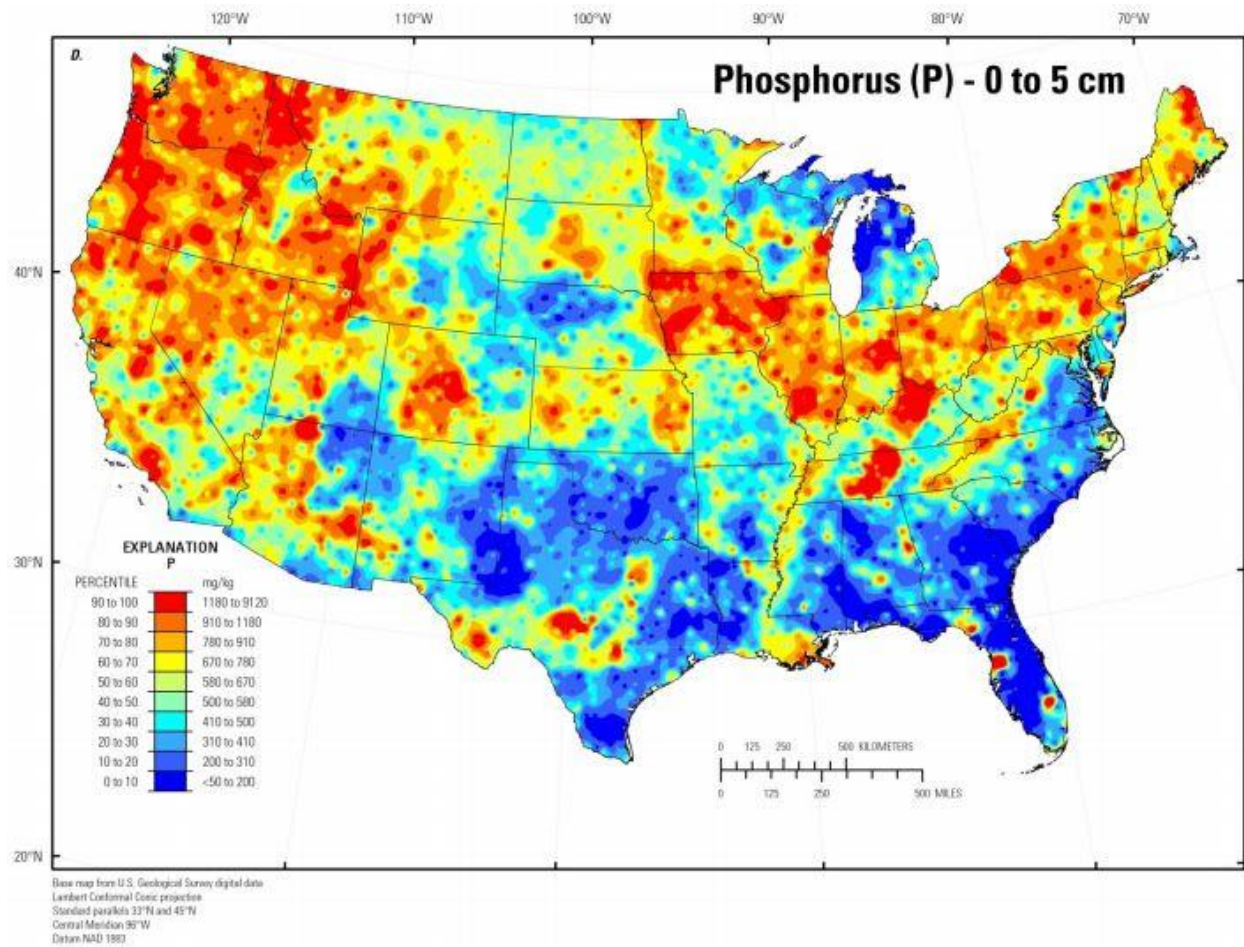
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Figure 3. USGS Map of Manganese Concentrations in Surface Soil



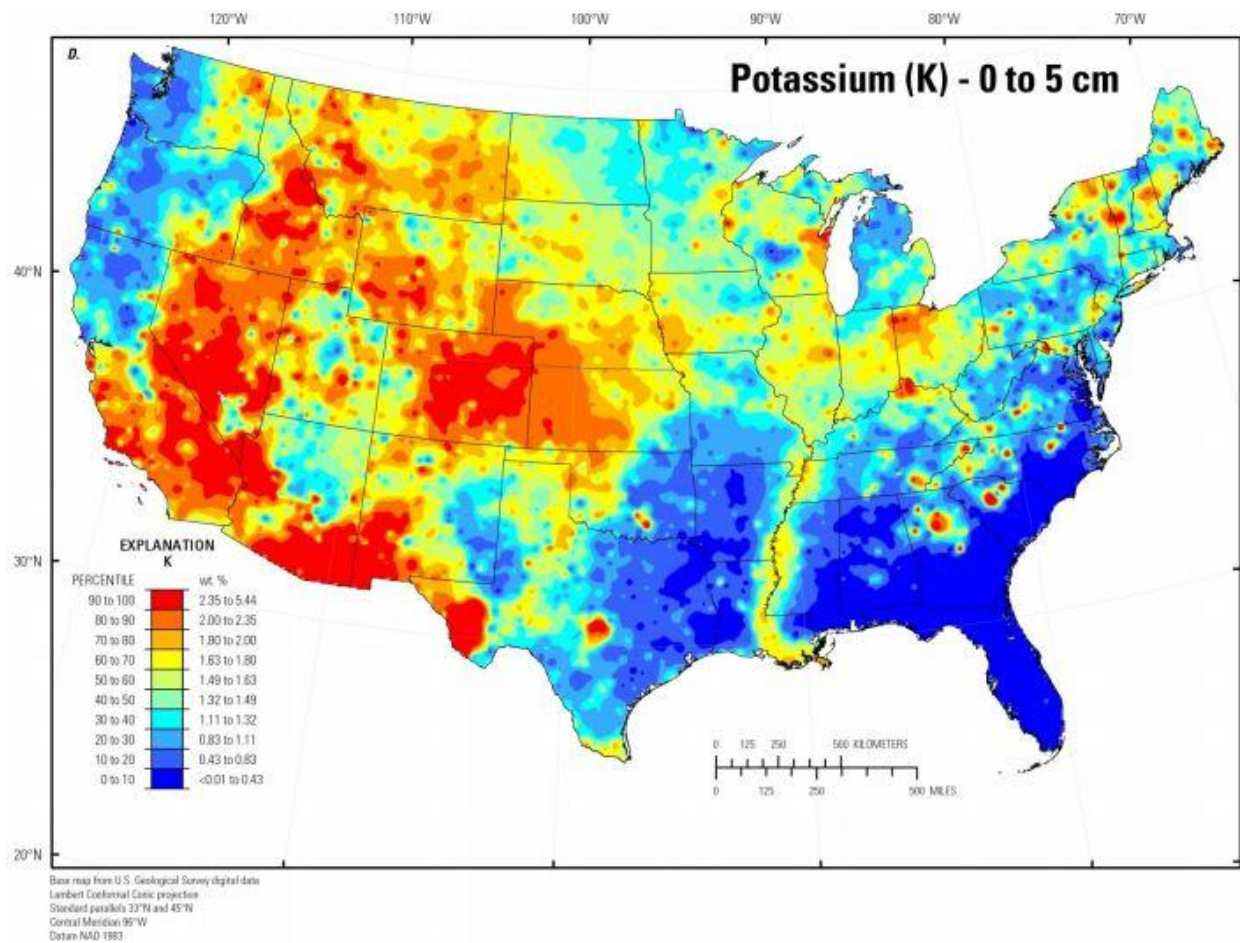
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Figure 4. USGS Map of Phosphorus Concentrations in Surface Soil



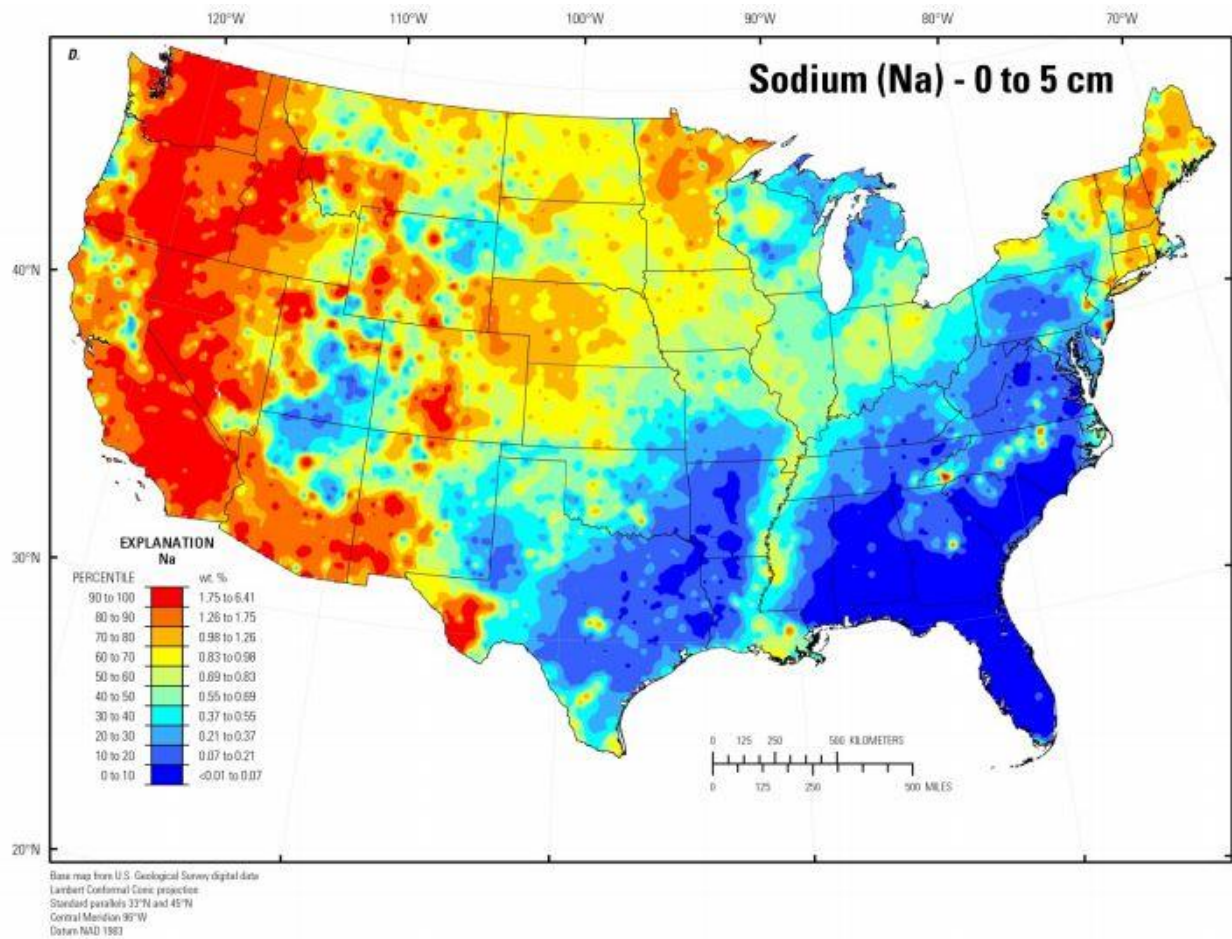
<https://pubs.usgs.gov/sir/2017/5118/elements/Phosphorus/OFR-2014-1082-P.pdf>

Figure 5. USGS Map of Potassium Concentrations in Surface Soil



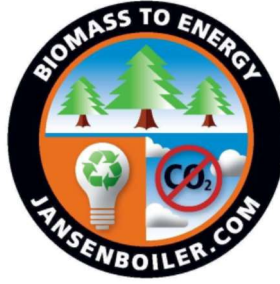
<https://pubs.usgs.gov/sir/2017/5118/elements/Potassium/OFR-2014-1082-K.pdf>

Figure 6. USGS Map of Sodium Concentrations in Surface Soil



<https://pubs.usgs.gov/sir/2017/5118/clements/Sodium/OFR-2014-1082-Na.pdf>

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May 10, 2021

Via E-mail

Ms. Rhonda Smith
Environmental Engineer
Boise Cascade Wood Products, LLC
90 South 21st Avenue
Elgin, OR 97827

**Re: Report for Evaluation to Define NO_x Reduction Options for the Wood Fired Boilers at the Elgin Plant
Jansen Project No. 2021-0028**

Dear Rhonda:

This letter describes Jansen Combustion and Boiler Technologies, Inc.'s (JANSEN's) screening evaluation of the Boise Cascade Wood Products, LLC (Boise) wood fired boilers in Elgin, Oregon for the purpose of defining nitrogen oxides (NO_x) reduction options using combustion control technologies.

1. Background and Goals

Boise operates two identical wood derived fuel (WDF) boilers supplied by the Keeler Company at its plant in Elgin, Oregon. The power boilers were designed to generate up to 60,000 lb/hr of saturated steam at 450 psig.

Boise is considering its options regarding Oregon's Regional Haze Rule that the Department of Environmental Quality (DEQ) is planning on implementing and that would require lowering NO_x emissions from Boise's Elgin boilers. Specifically, Boise is interested in combustion control options to reduce NO_x emissions.

JANSEN representatives visited the Elgin plant on April 6, 2021 to meet with Boise personnel and collect limited operating data on the No. 2 Boiler (see summary in Appendix A). The data helped define current operation and NO_x levels, which then in turn was used to find feasible reduction options. Expected ranges of achievable reduction targets for each option were taken from the literature and JANSEN's experience with many other WDF firing boilers considering the boiler specific information. Expected ranges of cost for each technology were taken from the literature or past projects and should be considered as loose budgetary ranges. Further evaluation steps will be required to better define NO_x reduction levels and cost in following phases once a path forward is chosen by Boise.



2. Description of Current Boiler Operation

The boilers are equipped with stationary water-cooled grates. Grates are manually raked three times per day, one section at a time until all three sections per boiler are raked. The grate is approximately 11 feet deep by 13 feet wide, and the furnace is approximately 24 feet tall.

For each unit, fuel is supplied to the boiler furnace through three “old style” Detroit Stoker Company fuel distributors. The flue gas leaving the furnace passes through a generating bank section, a tubular air heater (TAH), and mechanical dust collector (MDC) to the induced draft (ID) fan. Downstream of the ID fans the flue gas ducting from both units combine prior to flowing through a common electrostatic precipitator (ESP) and exhaust through a stack.

For each unit, ambient combustion air supplied by a forced draft (FD) fan is heated in the TAH before being supplied through the grate as undergrate air (UGA). The FD fan motor is equipped with a variable frequency drive (VFD) to automatically adjust the fan speed with changes in fuel feed rate. Additionally, two ambient fans provide combustion air to three rows of ports above the grate and the fuel distributors (including five ports under each distributors). These three rows of ports above the grate are located on the front and rear wall consisting of small ports. The row on the front wall is located approximately 3 feet above the center of the fuel distributor openings. The lower row of ports on the rear wall is located below the fuel distributor elevation while the upper approximately 1.3 feet above the center of the distributors. The ambient air flow to ports above the grate and the fuel distributors is typically maintained at a constant level leading to higher flue gas oxygen levels at lower load operation.

The boilers are not equipped with air flow meters. Flue gas oxygen is measured for each unit at the MDC outlet (on a wet basis). There is no easy access to the ducting above the TAH. Therefore, in-leakage in the TAH could not be field measured during JANSEN's visit. JANSEN performed measurements at the MDC inlet and the stack.

Current emission limits are 0.66 lb of carbon monoxide (CO) per thousand pounds of steam and 0.42 lb of NO_x per thousand pounds of steam, measured with a periodic stack test.

On rare occasions when the WDF is very wet, ply trim is added to the fuel stream. Ply trim contains small amounts of glue with resin containing nitrogen. In JANSEN's experience ply trim with glue resin can increase NO_x emissions, but since it is rarely burned in the Elgin units this is not a major concern.

3. Background on NO_x Generation in Boiler Wood Combustion

In WDF combustion, NO_x is generated from nitrogen in the fuel reacting with oxygen in the air, also called “fuel NO_x”. NO_x generation in WDF combustion is a function of the nitrogen content in the fuel, which varies typically some between wood species (for example, higher for beech and oak compared to fir) but can be elevated if nitrogen-based glues are contained in some of the fuels. For example, sander dust can often have higher nitrogen contents than regular wood. Also, burning wood containing debris from construction can also have higher nitrogen contents.

Another variable impacting NO_x generation is the flue gas oxygen content. NO_x emissions are approximately linear with flue gas oxygen concentration. Combustion technologies that stage combustion creating fuel rich (air lean) zones either by staging the combustion air and/or the fuel will



reduce NO_x emissions. Generating fuel NO_x is temperature dependent, but much less than Thermal NO_x from fossil fuel combustion. Water or steam injection is a combustion technology often applied to control NO_x for boilers burning fossil fuel. Often co-firing a small amount of auxiliary fuel such as natural gas (NG) can be beneficial in reducing NO_x emissions.

4. November 20, 2019 Title V Stack Test Information

The November 20, 2019 stack test was reviewed to gain additional information on boiler operation and emissions. The combined steam flow during the test was 91,300 lb/hr. The two fuel samples collected as part of the stack test indicated a nitrogen content of 0.26% (by mass) and 0.22% (by mass) on a dry basis while the moisture contents were 44% (by mass) and 47% (by mass). These reported nitrogen contents are in the expected range for WDF burned in industrial boilers.

Figure 1 plots the CO and NO_x emission concentrations, corrected to 3% dry flue gas oxygen, versus stack flue gas oxygen for the three test runs. The typically parabolic relationship of CO versus oxygen can be seen with most of the points around the minimum indicating an operation near its optimum based on CO operation with current hardware and combustion air splits. The linear relationship of NO_x versus oxygen is also seen. The stack test average oxygen was 8.93% (by vol., dry) and CO and NO_x averages were 417 ppm and 185 ppm, respectively (both dry, corrected to 3% dry flue gas oxygen) corresponding to 0.32 lb/MMBtu of CO and 0.25 lb/MMBtu of NO_x.

The CO emission limits of 0.66 lb per thousand pounds of steam correspond to approximately 457 ppm (dry and corrected to 3% dry flue gas oxygen) or 0.35 lb/MMBtu indicating a margin of about 9% (see Section 5.1 for further discussion).

5. Options to Reduce NO_x

The following combustion and trim technologies are commonly applied to reduce NO_x emissions from boilers burning WDF:

- Low oxygen operation
- Air staging: overfire air (OFA) with one or more levels
- Flue gas recirculation (FGR)
- NG co-firing or fuel staging
- Steam or water injection

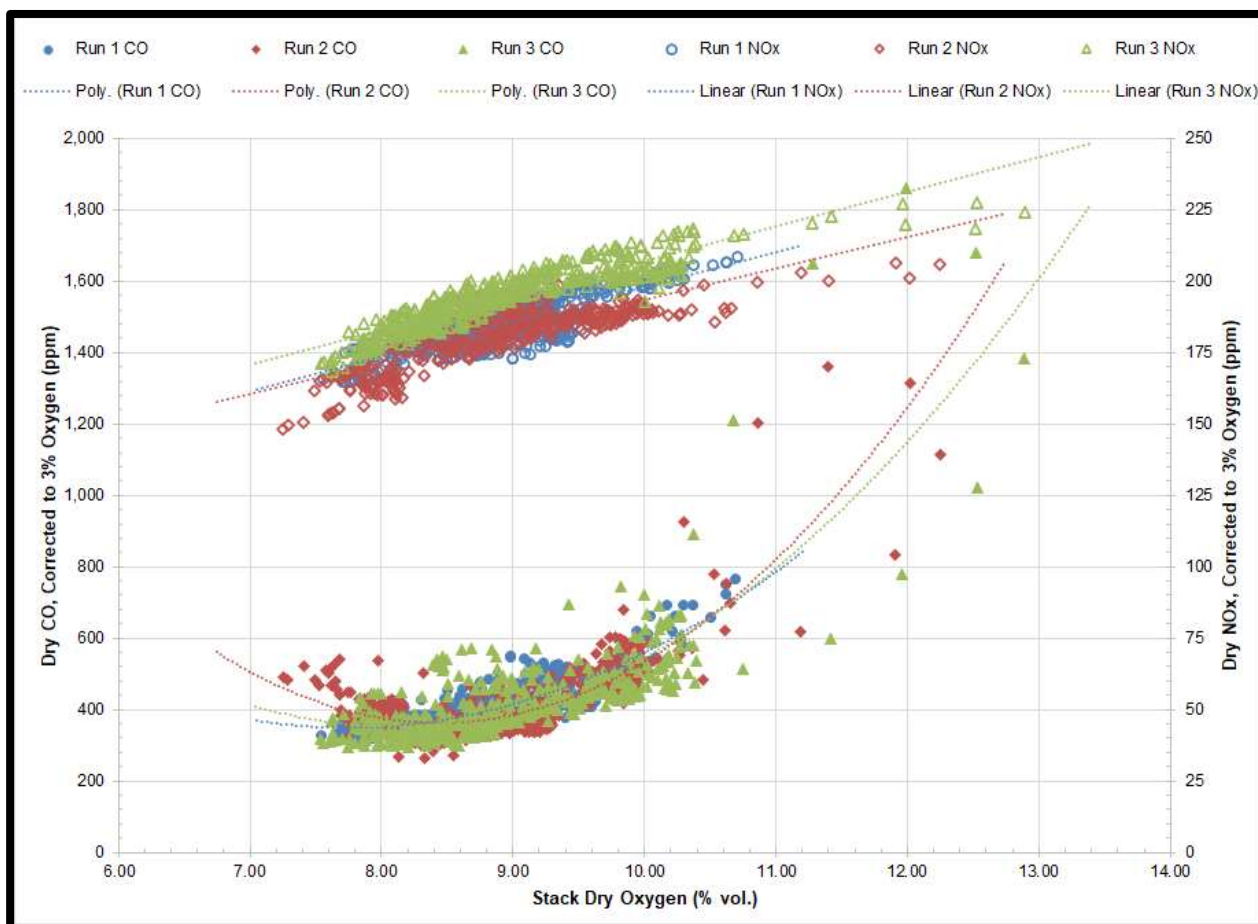


Figure 1. Stack Test CO and NO_x versus Flue Gas Oxygen

5.1 Low Oxygen Operation

As seen from Figure 1, NO_x concentrations are approximately linear with flue gas oxygen with its slope impacted by parameters such as air staging (for example elevation of OFA ports above grate, number of OFA elevation, fraction of combustion air supplied through OFA ports, etc.) and fuel nitrogen content. So often it is possible to reduce NO_x emissions by reducing flue gas oxygen and implementing improved flue gas oxygen control. Reducing flue gas oxygen is typically limited by two factors, CO emissions and grate piling.

As seen from Figure 1, CO concentrations are a parabolic, or “U” shaped, function of the flue gas oxygen with minimum CO at an optimum flue gas oxygen, and higher CO at oxygen values higher and lower than this optimum. The actual optimum flue gas oxygen is also impacted by air in-leakage into the flue gas, but the general shape of this relationship is impacted by parameters associated with the OFA system and its performance. For example, a highly effective and optimally designed OFA system supplying an adequate fraction of the combustion air would shift the minimum CO and the optimum flue gas oxygen simultaneously lower. Therefore, operation with reduced flue gas oxygen to reduce



NO_x emissions will be limited by the CO emissions compared to the applicable regulatory limit since once the flue gas oxygen drops lower than the optimum for CO, CO will increase.

For the stack test data in Figure 1 this means that the average stack flue gas oxygen could be as low as approximately 7.8% (by vol., dry) to average the CO limit of 457 ppm (dry, corrected to 3% dry oxygen), or 0.66 lb/Mlb of steam. This compares to the actual test average of 8.9%. This would then lead to **reduced NO_x concentrations of approximately 6% (from 185 to approximately 173 ppm, both dry and corrected to 3% oxygen)**. Of course, this would not account for any desired operating margin. Therefore, the potential reduction from low oxygen operation is rather small based on the stack test data because the units were operating near their optimum flue gas oxygen.

The second parameter that can limit low oxygen operation is grate piling. Flue gas oxygen is reduced by reducing the combustion air supply to the boilers either through the grate or through ports above the grate. However, the mass flow through the grate cannot be reduced beyond a certain threshold without causing excessive grate piling. This is further discussed in the next two sections.

5.2 Air staging: OFA with One or More Levels

Supplying a larger fraction of the combustion air above the grate will reduce NO_x emissions. This will stage combustion such that less oxygen is available in the lower furnace which benefits NO_x emissions. While OFA ports can be arranged in more than one elevation for further benefits, sufficient residence time between the highest level and the furnace exit is required for proper CO burnout. A higher fraction of the combustion air supplied through properly staged OFA ports typically will lead to lower NO_x concentrations, but the maximum fraction of OFA is limited by the grate size and boiler load since a minimum mass flow must be supplied through the grate to prevent excessive piling on the grate.

Figure 2 shows NO_x emissions for another similar boiler burning WDF on a traveling grate without fossil fuel co-firing as an example of achievable NO_x emissions that can be expected from the Elgin units with air staging. The figure shows NO_x emissions versus oxygen for three different fractions of OFA supply. The average November 2019 Elgin stack test point is included for comparison. The following can be seen from the figure and the Elgin boiler OFA system arrangement:

1. Higher fraction of OFA provide lower NO_x emissions (for example, increasing the fraction of OFA from 16% to 25% reduced NO_x by 15% to 22% on other boilers).
2. The level of NO_x concentration from the Elgin boilers is high considering the fuel nitrogen content and excess air. This is caused by a lack of proper air staging through OFA ports. Most of the OFA ports (except the upper front wall ports) in the Elgin boilers are located close to the grate which provides little staging of the combustion air and therefore do not benefit low NO_x generation.
3. Replacing the existing OFA ports with a properly staged single level sidewall OFA system supplying an adequate fraction of the total combustion air is expected to significantly reduce NO_x emissions and allow operation at lower average flue gas oxygen while still controlling CO emissions. Additionally, we recommend replacing the fuel distributors with the “newer style” provided by Detroit Stoker Company. These new style distributors will no longer require a row of ports below them, therefore allowing further staging of that air. It is expected that these

modifications could **reduce NO_x emissions by 15% to 26%**. However, more detailed evaluations would be required to determine if the upper range or reduction could be reached without also applying FGR (see below). Therefore, we assume that a reduction range of 15% to 20% would be more realistic without FGR.

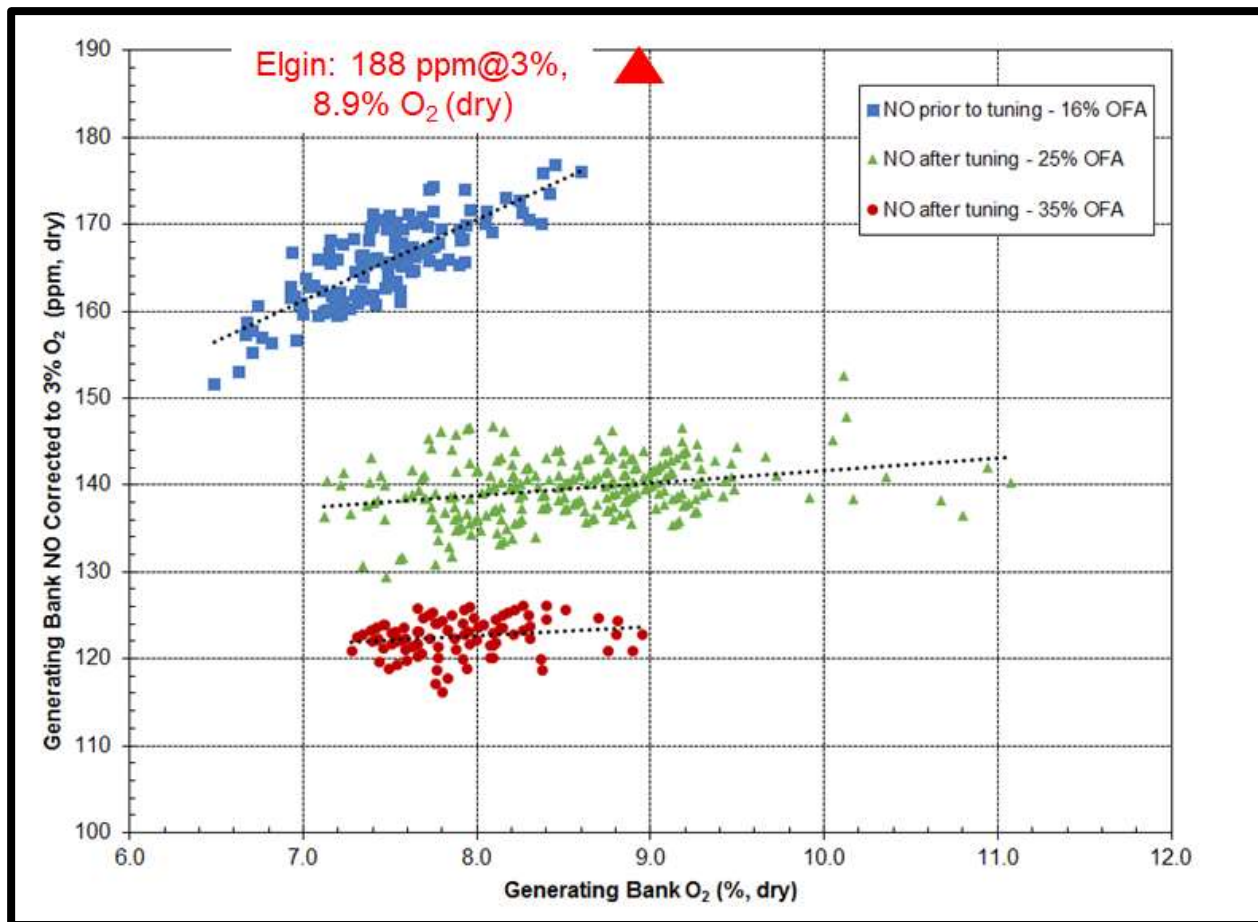


Figure 2. Example of NO_x vs. Oxygen with Varying OFA Fraction for Boiler A Burning 100% WDF

5.3 FGR

As discussed above, a certain minimum mass flux through the grate is required to avoid excessive piling. This is especially important on stationary grates that are designed for lower heat fluxes, and for boilers often operating at reduced loads, which both apply for the Elgin units. This limits how much the combustion air flow and excess air can be reduced, and therefore impacts the achievable NO_x emissions. Once the minimum required mass flux through the grate is reached, the flue gas oxygen cannot be further reduced unless further measures are taken.

FGR is a method that takes a portion (up to 10%) of clean flue gas (extracted downstream of the ESP) for supply with combustion air through the grate. This helps in maintaining the required mass flux through the grate and allows more of the combustion air to be supplied above the grate through OFA



ports while FGR further reduces oxygen availability between the grate and OFA port elevation. Applying FGR together with a new OFA system and replaced fuel distributors (see previous section) will assure NO_x reduction rates towards the higher end of the 15% to 26% range (for example 20% to 26%).

5.4 NG Co-firing or Fuel Staging

Co-firing NG with WDF tends to reduce overall NO_x concentrations. NO_x from NG is Thermal NO_x generated from the nitrogen in the air. Thermal NO_x generation is highly temperature dependent, but NG combustion generates less NO_x at lower temperatures than WDF. Providing a small fraction of heat input from NG will still assure low to moderate temperatures preventing significant Thermal NO_x generation. Achievable reductions (at constant flue gas oxygen) are about 2.5% for every 10% of heat input from NG at low NG firing rates and about twice as much after that (for example, approximately 2.5%, 5.0%, 7.5%, 15%, and 19% NO_x reduction for 10%, 20%, 30%, 40%, and 50% heat input from NG, respectively).

The Elgin boilers are currently not equipped with NG burners. Combustion of NG will replace a portion of the carbon-neutral biomass fuel and generate greenhouse gas emissions.

5.5 Steam or Water Injection

The purpose of steam or water injection is to cool furnace temperatures. This is often applied in oil or coal combustion where Thermal NO_x is important. Fuel NO_x reactions are less temperature dependent and temperatures for WDF combustion are typically significantly lower due to the lower heating value and high fuel moisture content. Therefore, steam or water injection is not typically applied to reduce NO_x from WDF combustion and not recommended for the Elgin boilers.

6. Conclusions and Recommendations

Figure 3 summarizes estimates for the achievable NO_x reduction ranges for the Elgin boilers and includes cost values per ton of NO_x from the literature. Please note that these literature values for cost are based on large utility boilers most of them burning coal. The cost per annual tons of NO_x reduction in Figure 3 are meant to be used for comparison purpose between the different technologies only. We expect significantly higher costs for small boilers like the Elgin units and less NO_x reductions, on a percentage bases, for units burning WDF instead of coal. Both points will significantly increase the price per annual ton of NO_x reduction.

Table 1 provides pros and cons for each of the discussed reduction technologies. Considering achievable NO_x reduction and cost as well as pros and cons, we recommend a combination of staged combustion and FGR. Specifically, this would require the following boiler modifications:

- a. New fuel distributors on each boiler.
- b. New OFA system with hot OFA booster fan on each boiler.
- c. New FGR system with one common FGR booster fan supplying both boilers.
- d. Improved combustion air and flue gas oxygen controls.



The budget cost for engineering, design, equipment supply, and installation for the above scope would be approximately **\$1.77 million** (approximately +/-50% accuracy) with both boilers being modified at the same time. This includes construction observation, operator training, and initial start-up support, but excludes items such as electrical, controls (often approximately \$50,000 to \$100,000 depending on the current system capability), and structural steel/engineering. It also assumes that the installation could be performed by a local mechanical contractor, assuming no pressure part work is required.

Note these costs are budgetary and the NO_x reduction values are estimated ranges. More detailed process and design engineering is required to further define costs and benefits in a next phase. Once Boise has decided on a path forward, JANSEN recommends a Phase 1 process engineering evaluation to better define the required modification scope and achievable NO_x emission. A **Phase 1** engineering evaluation typically would be in the **\$50,000 to \$70,000** range including computational fluid dynamics modeling. The price for this Phase 1 evaluation is included in the above budget cost. Following the Phase 1 evaluation, JANSEN would be in a position to provide a fixed fee proposal for the design, engineering, and supply of the proposed modifications plus a more accurate installation cost (approximately +/-30%).

If Boise requires a more accurate definition of the installation cost, a definition engineering phase could be added that would deliver preliminary arrangement drawings to obtain a more accurate installation cost.

Technology	Achievable Max. Range for Elgin Boilers	Installation Cost Based on Literature (\$/ton NO _x)***
Low Oxygen Operation	Up to 6% reduction	small
Air Staging	15-20% reduction	250 to 500
FGR	20-26% reduction*	200 to 500
NG Co-firing	Up to ~19% reduction**	500 to 800
*Values together with air staging. **With up to 50% heat input from natural gas ***Actual cost likely significantly higher for small units burning WDF		

Figure 3. Achievable NO_x Reduction Ranges and Cost Values from the Literature for Comparison Purpose




Table 1. Pros and Cons of NO _x Reduction Technologies		
Control Technologies	Pros	Cons
Low oxygen operation	<ul style="list-style-type: none"> Minimal costs. 	<ul style="list-style-type: none"> Low NO_x reduction potential.
Air staging	<ul style="list-style-type: none"> No chemical usage. More flexible to load changes. 	<ul style="list-style-type: none"> Success limited w/o FGR due to limitations to reduce UGA.
FGR	<ul style="list-style-type: none"> Increased flexibility together with air staging. Allows further staging while maintaining UGA flux to prevent piling. Up to 26% NO_x reduction together with air staging. 	<ul style="list-style-type: none"> Additional cost due to booster FGR fan. Expected small increase in ESP inlet loading. Small increase in flue gas flow rates and ID fan load.
NG co-firing	<ul style="list-style-type: none"> Potentially cost effective for boilers with existing burners which does not apply to Elgin units. 	<ul style="list-style-type: none"> Requires burner installation which is costly. Large fractional heat input from NG are needed for significant reductions. Generates greenhouse gases. NG more costly than WDF even after correcting for boiler efficiency.

We appreciate the opportunity to be of service to Boise Cascade Wood Products, LLC at the Elgin Plant. Please contact me if there are any questions regarding this report and/or to discuss next steps.

Sincerely,


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MDB/SJP:cjt
Attachment

Appendix A: Data Summary

JANSEN*Combustion and Boiler Technologies, Inc.***SUMMARY OF DCS OPERATING DATA**

Instrument Name	Tag	Units	Data Collection 4/06/2021 11:10 to 14:40	Testo MDC Inlet Collection 4/06/2021 12:24 to 13:00
Steam and Feedwater				
Boiler 1 Steam Flow	Elgin.InSQL.ELPH_ElginBoilers_B1_SteamFlow/PLOT	1,000 lbs/hr	16.5	16.5
Boiler 2 Steam Flow	Elgin.InSQL.ELPH_ElginBoilers_B2_SteamFlow/PLOT	1,000 lbs/hr	36.5	34.2
Combined Boilers Steam Flow	Elgin.CALC.ELPH_Calc_BoilersCombinedSteamOutputCalc/PLOT	1,000 lbs/hr	52.9	50.7
Boiler Make Up Water	Elgin.InSQL.ELPH_ElginBoilers_MakeUpWaterTransmitter/PLOT	lbs/hr	21	18
Boiler Feed Water Pressure	Elgin.InSQL.ELPH_ElginBoilers_FeedWaterPressure	psig	462	467
DA Tank Pressure	Elgin.InSQL.ELPH_ElginBoilers_DATankPressure/PLOT	psig	12	12
Da Temperature	NA	°F	227	227
Fuel				
Boiler 1 Fuel Auger 1 RPM	Elgin.InSQL.ELPH_ElginBoilers_B1_FUEL1_RPM/PLOT	rpm	3.8	3.5
Boiler 2 Fuel Auger 1 RPM	Elgin.InSQL.ELPH_ElginBoilers_B2_FUEL1_RPM/PLOT	rpm	5.0	4.1
Boiler 1 Fuel Auger 2 RPM	Elgin.InSQL.ELPH_ElginBoilers_B1_FUEL2_RPM/PLOT	rpm	4.9	4.1
Boiler 2 Fuel Auger 2 RPM	Elgin.InSQL.ELPH_ElginBoilers_B2_FUEL2_RPM/PLOT	rpm	4.6	3.8
Boiler 1 Fuel Auger 3 RPM	Elgin.InSQL.ELPH_ElginBoilers_B1_FUEL3_RPM/PLOT	rpm	4.7	4.1
Boiler 2 Fuel Auger 3 RPM	Elgin.InSQL.ELPH_ElginBoilers_B2_FUEL3_RPM/PLOT	rpm	4.7	3.9
<div> <div>Client: Boise Cascade</div> <div>Location: Elgin, OR</div> <div>Project:</div> </div> <div> <div>Job No.: 2021-0027</div> <div>By: TLS</div> <div>Page 1 of 2</div> </div>				

JANSEN*Combustion and Boiler Technologies, Inc.***SUMMARY OF DCS OPERATING DATA**

			Data Collection 4/06/2021 11:10 to 14:40	Testo MDC Inlet Collection 4/06/2021 12:24 to 13:00
Instrument Name	Tag	Units		
Combustion Air				
Boiler 1 FD Fan Speed	Elgin.InSQL.ELPH_ElginBoilers_B1_FDFanFeedback/PLOT	rpm	1378	1295
Boiler 2 FD Fan Speed	Elgin.InSQL.ELPH_ElginBoilers_B2_FDFanFeedback/PLOT	rpm	1334	1298
Flue Gas				
Boiler 1 Furnace Pressure	Elgin.InSQL.ELPH_ElginBoilers_B1_FurnacePressure/PLOT	in. wg	-0.25	-0.25
Boiler 2 Furnace Pressure	Elgin.InSQL.ELPH_ElginBoilers_B2_FurnacePressure/PLOT	in. wg	-0.27	-0.25
Boiler 1 Furnace Temperature	Elgin.InSQL.ELPH_ElginBoilers_B1_FurnaceTemp/PLOT	°F	1200	1111
Boiler 2 Furnace Temperature	Elgin.InSQL.ELPH_ElginBoilers_B2_FurnaceTemp/PLOT	°F	1372	1269
Boiler 1 Current O2	Elgin.InSQL.ELPH_ElginBoilers_B1_CurrentO2/PLOT	%, wet	10.1	11.4
Boiler 2 Current O2	Elgin.InSQL.ELPH_ElginBoilers_B2_CurrentO2/PLOT	%, wet	9.8	11.1
Boiler 1 Stack Temperature	Elgin.InSQL.ELPH_ElginBoilers_B1_StackTemp/PLOT	°F	442	428
Boiler 2 Stack Temperature	Elgin.InSQL.ELPH_ElginBoilers_B2_StackTemp/PLOT	°F	497	476
Opacity 1 Minute Average %	Elgin.InSQL.ELPHBO_Opacity1MinAvg/PLOT	%	0.02	0.02
Boiler 1 ID VFD	Elgin.InSQL.ELPH_ElginBoilers_B1_IDDamp_VFD/PLOT	rpm	52.1	52.1
Boiler 2 ID VFD	Elgin.InSQL.ELPH_ElginBoilers_B2_IDDamp_VFD/PLOT	rpm	67.2	67.2

Client: Boise Cascade**Location: Elgin, OR****Project:****Job No.: 2021-0027****By: TLS****Page 2 of 2**

Steam and Power Engineers

[illegible]

Steam and Power Engineers

FLUE GAS	Date	4/6/21					
	Time	O ₂ (% dry)	Plant O ₂	CO (ppm dry)	NO (ppm dry)	Temp. (°F)	Pressure (in. wg)
Mechanical Dust Collector Inlet (LHS)	12:27:00	13.9		1,119	86	475	
	12:27:30	14.1		1,410	77	476	
	12:28:00	13.6		1,215	80	477	
	12:28:30	12.6		706	91	479	
	12:29:00	11.7		462	103	480	
	12:29:30	11.4		423	108	480	
	12:30:00	11.5		420	109	479	
	12:30:30	12.3		478	104	475	
	12:31:00	13.6		767	94	472	
	12:31:30	15.0		1,693	83	471	
	12:32:00	15.7		2,770	74	473	
	12:32:30	14.9		2,711	63	474	
	12:33:00	12.9		1,239	79	474	
	12:33:30	12.4		654	90	474	
	12:34:00	12.4		501	94	472	
	12:34:30	12.5		520	93	469	
	12:35:00	12.8		522	93	464	
	12:35:30	13.8		769	82	461	
	12:36:00	15.3		891	81	460	
	12:36:30	15.3		2975	72	461	
	12:37:00	14.9		2813	64	463	
	12:37:30	13.7		1986	70	468	
	Average	13.5		1229	86	472	NM
Stack Outlet	1:16:00	11.4		325	119	412	
	1:16:30	11.4		320	119	412	
	1:17:00	11.3		312	120	412	
	1:17:30	11.3		312	120	413	
	1:18:00	11.3		317	120	413	
	1:18:30	11.3		321	119	414	
	1:19:00	11.3		322	119	414	
	1:19:30	11.2		319	120	414	
	1:20:00	11.2		322	122	415	
	1:20:30	11.3		329	122	415	
	1:21:00	11.2		323	123	415	
	1:21:30	11.2		329	124	415	
	1:22:00	11.5		333	123	415	-0.02
	Average	11.3		322	121	414	-0.02
NM = Not measured							