REGIONAL HAZE FOUR-FACTOR ANALYSIS

OCHOCO LUMBER COMPANY

Prepared for

OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY

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

Prepared by
Maul Foster & Alongi, Inc.
6 Centerpointe Drive, Suite 360, Lake Oswego, OR 97035

MAUL
FOSTER
ALONGI

CONTENTS

LIMITATIONS

TABLES

ACRONYMS AND ABBREVIATIONS

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

1 INTRODUCTION

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

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

(1) The cost of control,

(2) The time required to achieve control,

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

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

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

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

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

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

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

1.1 Facility Description

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

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

1.2 Process Description

1.2.1 Lumber Manufacturing

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

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

1.2.2 Torrefied-Wood Production

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

2 APPLICABLE EMISSION SOURCES

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

---

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

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

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

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

2.1 Sources of PM_{10} Emissions

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

2.1.1 Torrefier (TORR)

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

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

2.1.2 Boiler 3 (BLR3)

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

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

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

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

2.1.3 Boilers 1 and 2 (BLR1 and BLR2)

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

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

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

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

2.1.4 Unpaved Roads

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

2.2 Sources of NO_X Emissions

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

2.3 Sources of SO_2 Emissions

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

2.4 Emission Unit Exhaust Parameters

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

3 REGIONAL HAZE FOUR FACTOR ANALYSIS METHODOLOGY

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

3.1 Step 1: Determine Emission Control Measures to Consider

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

3.2 Step 2: Selection of Emissions

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

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

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

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

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

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

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

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

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

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

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

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

4 PM_{10} ANALYSIS

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

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

4.1.1 Baghouses

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

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

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

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

4.1.2 Wet Venturi Scrubbers

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

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

4.1.3 Electrostatic Precipitator

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

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

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

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

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

4.2 Step 2—Selection of Emissions

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

4.3 Step 3—Characterizing Cost of Compliance

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

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

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

4.4 Step 4—Characterizing Time Necessary for Compliance

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

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

4.5.1 Energy Impacts

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

4.5.2 Environmental Impacts

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

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

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

4.6 Step 6—Characterize the Remaining Useful Life

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

5 NO_X ANALYSIS

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

5.1 Step 1—Determine NO_X Control Measures for Consideration

5.1.1 Selective Non-catalytic Reduction

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

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

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

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

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

5.1.2 Selective Catalytic Reduction and Hybrid Systems

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

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

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

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

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

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

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

5.2 Step 2—Selection of Emissions

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

5.3 Step 3—Characterizing Cost of Compliance

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

Table 5-1
Cost of Compliance Summary for NO_X

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

5.4 Step 4—Characterizing Time Necessary for Compliance

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

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

5.5.1 Energy Impacts

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

5.5.2 Environmental Impacts

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

5.6 Step 6—Characterize the Remaining Useful Life

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

6 SO_2 ANALYSIS

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

6.1 Step 1—Determine SO_2 Control Measures for Consideration

6.1.1 Dry Sorbent Injection

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

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

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

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

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

6.2 Step 2—Selection of Emissions

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

6.3 Step 3—Characterizing the Cost of Compliance

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

6.4 Step 4—Characterizing Time Necessary for Compliance

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

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

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

6.6 Step 6—Characterize the Remaining Useful Life

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

7 CONCLUSION

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

LIMITATIONS

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

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

TABLES

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

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

Color Key
MFA-specific ID.

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

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

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

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

NOTES:

NO_x = oxides of nitrogen.

SNCR = selective catalytic reduction.

SNCR = selective non-catalytic reduction.

REFERENCES:

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

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

Table 2-3
SO_2 Evaluation for Regional Haze Four Factor Analysis
Malheur Lumber Company—John Day, Oregon

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

NOTES:

SO_2 = sulfur dioxide.

REFERENCES:

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

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

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

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

NOTES:

°F = degree Fahrenheit.

acfm = actual cubic feet per minute.

ft/sec = feet per second.

MMBtu/hr = million British thermal units per hour.

NO_x = oxides of nitrogen.

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

scfm = standard cubic feet per minute.

SO_2 = sulfur dioxide.

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

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

REFERENCES:

(1) Data provided by Malheur Lumber Company.

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

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

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

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

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

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

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

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

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

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

NOTES:

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

Control efficiency (%) = 99.0 (3)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Control device capital recovery factor = 0.0947 (k)

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

REFERENCES:

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

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

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

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

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

NOTES:

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

Control efficiency (%) = 99.0 (3)

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

Average specific collection area (ft^2/1,000 scfm) = 400 (3)

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

Annual hours of operation (hrs/yr) = 8,760 (6)

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

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

Site preparation cost, SP ($) = 0 (8)

Building cost, Bldg. ($) = 0 (8)

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

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

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

Control device capital recovery factor = 0.0786 (i)

(i) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs} - 1]; see reference (10).

Interest rate (%) = 4.75 (11)

Dry ESP economic life (yr) = 20 (12)

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

Operator labor rate ($/hr) = 22.00 (6)

Operating labor hours per shift [hrs/shift) = 2.00 (6)

Shifts per day (shifts/day) = 3 (6)

Annual days of operation (days/yr) = 365 (6)

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

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

(m) Maintenance labor cost ($-1999) = (maintenance labor cost [$-1999]) / (1999 annual chemical engineering plant cost index) x (2019 annual chemical engineering plant cost index)

Maintenance labor cost ($-1999) 4,125 (14)

1999 annual chemical engineering plant cost index = 390.6 (14)

2019 annual chemical engineering plant cost index = 607.5 (14)

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

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

Annual hours of operation (hrs/yr) = 8,760 (6)

Electricity rate ($/kWh) = 0.061 (6)

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

Annual hours of operation (hrs/yr) = 8,760 (6)

Electricity rate ($/kWh) = 0.061 (6)

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

Compressed air cost ($/Mscf) = 0.003 (6)

Annual hours of operation (hrs/yr) = 8,760 (6)

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

Annual hours of operation (hrs/yr) = 8,760 (6)

Landfilling cost ($/ton) = 57.00 (6)

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

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

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

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

REFERENCES:
(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.
(3) USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-028) for dry electrostatic precipitator, wire-plate type issued July 15, 2003. Assumes the typical collection area and minimum new equipment design control efficiency.
(4) PPC Industries Quotation no. 18048/18049 (Revision 0) dated September 12 and 13, 2018. MFA obtained two separate costs and equipment requirements for dry ESPs sized at 21,000 acfm and 51,000 acfm. For the smallest exhaust flowrate above (MC4), the quoted data was scaled using a ratio. All other costs/data were scaled and obtained using tread line formulas. It is important to note that the quoted costs do not include the costs associated with taxes, freight, mechanical construction, electrical work, excavation, building/foundation upgrades, and permitting or licensing.
(5) excavation, building/foundation upgrades, and permitting or licensing.
(6) See Table 3-1, Operating and Maintenance Rates.
(7) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.16 "Capital Cost Factors for ESPs."
(8) Conservatively assumes no costs associated with site preparation or building requirements.
(9) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(10) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(11) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(12) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See section 3.4.2.
(13) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See Table 3.21.
(14) See Chemical Engineering magazine, chemical engineering plant cost index section for annual indices.

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

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

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

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

NOTES:

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

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

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

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

Control efficiency (%) = 25.0 (4)

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

Control efficiency (%) = 25.0 (4)

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

Control efficiency (%) = 25.0 (4)

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

Theoretical stoichiometric ratio = 2 (7)

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

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

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

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

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

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

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

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

Density of water (lb/gal) = 8.345

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

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

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

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

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

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

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

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

Retrofit factor = 1.00 (15)

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

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

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

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

Control device capital recovery factor = 0.0786 (o)

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

Interest rate (%) = 4.75 (21)

SNCR economic life (yr) = 20 (22)

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

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

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

Reagent rate ($/50% urea solution) = 1.86 (r)

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

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

Reagent rate (2016 $/50% urea solution) = 1.66 (4)

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

Chemical engineering plant cost index for 2016 = 541.7 (14)

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

Electricity rate ($/kWh) = 0.061 (2)

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

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

Water rate ($/Mgal) = 14.5 (2)

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

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

High heat value of wood (MMBtu/BDT) = 17.48 (25)

Wood fuel rate ($/BDT) = 21.00 (2)

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

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

Ash production (wt%) = 1.75 (27)

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

High heat value of wood (MMBtu/BDT) = 17.48 (25)

Landfill disposal rate ($/ton) = 44.90 (2)

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

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

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

REFERENCES:

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

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

(17) Cost for storage tank and heating unit. Includes shipping and installation costs.
(18) Cost for construction of covered tank storage area and secondary containment.
(19) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(20) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(21) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(22) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.4.2.
(23) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.39.
(24) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.49.
(25) 40 CFR, Subchapter C, Part 98, Subpart C. See Table C-1 "Default CO2 Emission Factors and High Heat Values of Various Types of Fuel". Factor for wood and wood residuals.
(26) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equations 1.50 and 1.51.
(27) Average wood ash production from burning of hogged fuel.
(28) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.38.
(29) US EPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.52 and 1.53.