Swanson Group
Accountability
Commitment
Excellence
Safety

Swanson Group Manufacturing
PO Box 250
Glendale, OR 97442
Office (541) 832-1121
Fax (541) 832-1139
www.swansongroup.biz

June 1, 2020

DEPT OF ENVIRONMENTAL QUALITY
RECEIVED
JUN 03 2020
NORTHWEST REGION

Department of Environmental Quality
Agency Headquarters
700 NE Multnomah Street, Suite 600
Portland, OR 97232

Subject: Regional Haze Four Factor Analysis; Swanson Group Mfg.LLC

Per your request Swanson Group has completed the analysis for our plywood production facility in Glendale Oregon.

DEQ Facility ID:	10-0045
Federal Facility ID:	8004811
Facility name:	Swanson Group Mfg. LLC
Facility Address:	303 MEHLWOOD LANE Glendale, OR 97442

Sincerely

Jeff Remington

Jeff Remington
VP of Engineering
Office 541-832-1194
Cell 541-761-0533
E-fax 541-832-1433

REGIONAL HAZE FOUR FACTOR ANALYSIS

SWANSON GROUP MANUFACTURING

Prepared for
SWANSON GROUP MFG. LLC
GLENDALE, OREGON
May 29, 2020
Project No. 0472.04.01

MAUL FOSTER ALONGI

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

CONTENTS

ACRONYMS AND ABBREVIATIONS

$/ton	dollars per ton of pollutant controlled
°F	degrees Fahrenheit
Analysis	Regional Haze Four Factor Analysis
CAA	Clean Air Act
CFR	Code of Federal Regulations
Control Cost Manual	USEPA Air Pollution Control Cost Manual
DEQ	Oregon Department of Environmental Quality
ESP	electrostatic precipitator
existing permit	Title V Operating Permit no. 10-0045-TV-01
facility	veneer and plywood manufacturing facility located at 303 Mehlwood Lane, Glendale, Oregon 97442
Federal Guidance Document	Guidance on Regional Haze State Implementation Plans for the Second Implementation Period (August 2019), EPA-457/B-19-003
GACT	Generally Available Control Technology
HAP	hazardous air pollutant
hogged fuel boiler	Babcock and Wilcox Dutch-oven-type hogged fuel boiler
MFA	Maul Foster & Alongi, Inc.
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO	nitric oxide
NO_X	oxides of nitrogen
PCWP	Plywood and Composite Wood Products
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns or less
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
Swanson	Swanson Group Mfg. LLC
USEPA	U.S. Environmental Protection Agency
VOC	volatile organic compound

1 INTRODUCTION

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

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

(1) The cost of control,

(2) The time required to achieve control,

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

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

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

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

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

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

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

1.1 Facility Description

Swanson Group Mfg. LLC (Swanson) owns and operates a veneer and plywood manufacturing facility located at 303 Mehlwood Lane, Glendale, Oregon 97442 (the facility). Swanson was among the 31 industrial facilities requested by the DEQ to conduct an Analysis. The facility currently operates under

Title V Operating Permit no. 10-0045-TV-01 (existing permit) issued by the DEQ on June 12, 2017. The facility is a major stationary source of criteria pollutants only.

The facility is located due north of Glendale city center and is situated in a small valley that is surrounded by significant topographical features in each cardinal direction. It is important to note that the nearest federal Class I area is the Kalmiopsis Wilderness Area, approximately 48.8 kilometers southwest of the facility.

1.2 Process Description

Raw green logs from off-site sources are delivered to the facility by trucks and are stored in the log yard. Received logs are cut to length prior to conditioning in log vats. After conditioning, the logs are peeled to produce thin layers of green veneer, which are then sold or sent for drying. There are three veneer dryers at the facility.

After drying is complete, a portion of the dried sheets is sent to the patch process for finishing. In the patch process, adhesives are applied to sorted sheets to produce plywood sheets. Plywood sheets are then sent to one of three presses for curing. Once curing is complete, rough-cut plywood is further finished by repairing board imperfections, sanding, and cutting to final product dimensions. Heat used by each press, the log vats, and each veneer dryer is generated by the Babcock and Wilcox Dutch-oven-type hogged fuel boiler (hogged fuel boiler).

2 APPLICABLE EMISSION UNITS

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

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

This method of emission unit selection ensures that larger emission units are included in the Analysis. Larger emission units represent the likeliest potential for reduction in emissions that would contribute to a meaningful improvement in visibility at federal Class I areas. It would not be reasonable to assess many small emission units—neither on an individual basis (large reductions for a small source likely would not improve visibility and would not be cost effective), nor on a collective basis (the aggregate

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

emission rate would be no greater than 10 percent of the overall facility emissions rate, and thus not as likely to improve visibility at federal Class I areas, based solely on the relatively small potential overall emission decreases from the facility).

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

2.1 Sources of PM_{10} Emissions

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

2.1.1 Hogged Fuel Boiler (1PH)

Hogged fuel for use in the hogged fuel boiler is supplied primarily by off-site sources. However, residual bark, sanderdust, and plytrim generated on site are used when readily available. The hogged fuel boiler has a maximum rated heat input capacity of 125 million British thermal units per hour. Its rated design capacity is 75,000 pounds of steam per hour, which is used to provide heat for various types of equipment at the facility. Exhaust generated by operating the hogged fuel boiler is routed to a multiclone for control of coarse particulate emissions, then to a dry electrostatic precipitator (ESP) for control of fine particulate emissions. The hogged fuel boiler can also utilize process exhaust generated by operation of the three veneer dryers as a supplemental fuel source.

The hogged fuel boiler is subject to, and is required to comply with, Area Source Boiler Generally Available Control Technology (GACT) regulations, which are codified at Title 40 Code of Federal Regulations (CFR) 63 Subpart JJJJJJ, as introduced under Section 112(g) of the CAA. Based on USEPA guidance[2] provided to states for the Second Implementation Period, the USEPA believes that it is reasonable for states to exclude an emission source for further analysis if:

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

Based on the USEPA guidance, the hogged fuel boiler was excluded from further evaluation in the Analysis. It is also important to note that the hogged fuel boiler is already well controlled for fine particulate emissions by the state-of-the-art dry ESP.

---

[2] USEPA Office of Air Quality Planning and Standards. "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period." August 2019.

2.1.2 Veneer Dryer Fugitives (5VDa)

The veneer dryer fugitives emissions unit represents leaking emissions from seals, gaskets, and miscellaneous openings on the veneer dryers at the facility. Emissions from leaks are generated as fresh, green veneer is dried in each veneer dryer. The facility has a total of three veneer dryers (grouped in the existing permit as emission unit 5VD). Additional details describing the operation and size of each veneer dryer are presented in Section 2.1.2.1 for clarity.

Only PM_{10} emissions associated with the veneer dryer fugitives emissions unit (i.e., excluding emissions unit 5VD, point source veneer dryer emissions) meets the threshold of 90 percent contribution to the total facility PM_{10} emissions rate. However, each veneer dryer was recently rebuilt (within the last five years) in order to minimize the potential for fugitive emissions. There is also no reasonable way to capture fugitive emissions from veneer dryer leaks and route them to a downstream control device. Therefore, because of the recent reconstruction and the feasibility issues related to capturing and routing emissions, the veneer dryer fugitives emissions unit was excluded from further evaluation in the Analysis.

2.1.2.1 Veneer Dryers (5VD)

As stated above, there are three veneer dryers at the facility, which are used to dry green, freshly cut veneers to optimal moisture content depending on product specifications. Each veneer dryer at the facility is indirectly heated by steam generated by the hogged fuel boiler.

Veneer dryer no. 1 is a six-deck, two-zone Moore longitudinal dryer with a maximum drying capacity of 12,000 square feet per hour on a three-eighths-inch basis. Veneer dryer nos. 2 and 3 are four-deck, four-zone Moore jet dryers, each with a maximum drying capacity of 9,000 square feet per hour on a three-eighths-inch basis.

Process exhaust from the veneer dryers can be routed one of two ways, depending on the operating scenario. During operating scenario no. 1, process exhaust from the heated zones of each veneer dryer is routed through a heating coil, followed by a regenerative thermal oxidizer for control of volatile organic compound (VOC) and hazardous air pollutant (HAP) emissions. During operating scenario no. 2, process exhaust from the heated zones of each veneer dryer is routed to the hogged fuel boiler combustion zone for control of VOC and HAP emissions.

It is important to note that the veneer dryer emissions unit did not meet the threshold of 90 percent contribution to the total facility PM_{10} emissions rate. Therefore, the veneer dryers were not included in the Analysis and are presented here only for reference.

2.1.3 Plywood Press Nos. 1 through 3 (P1, P2, and P3)

There are three plywood presses at the facility, each hydraulically driven and heated, typically up to 300 degrees Fahrenheit (°F) above ambient temperature, via steam produced by the hogged fuel boiler. Uncontrolled plywood press emissions are produced during pressing and as the press is released, and are emitted to atmosphere via nearby roof vents.

Press no. 1 is a Columbia batch press with a rated capacity of 7.5 batches per hour, which is equivalent to 270 sheets per hour. Press no. 2, also a Columbia batch press, has a rated capacity of 7.5 batches per hour, which is equivalent to 225 sheets per hour. Press no. 3 is a Williams and White 30-opening plywood press with a rated capacity of 20,000 square feet per hour.

Plywood presses emit fugitive VOC and PM_{10} as sheets of wood veneer are pressed together using hot platens; they do not emit NOx or SO_2. Plywood assembly operations are located within a single large building. Because plywood presses are co-located with other process units, it is likely that the limited plywood press emissions data that have been collected by the National Council for Air and Stream Improvement (NCASI)[3] also includes fugitive emissions from other different types of process units in the same building. Nevertheless, estimated plywood press PM_{10} emissions are fairly small (less than 20 tons per year).

Plywood manufacturing facilities are subject to the NESHAP for Plywood and Composite Wood Products (PCWP) at 40 CFR 63, Subpart DDDD. Although veneer dryers are subject to standards, the USEPA determined that emissions from plywood presses were not amenable to capture and control and did not set any standards for these sources. The USEPA distinguished emissions control requirements for plywood presses from other reconstituted wood products presses (e.g., particleboard, oriented strand board, and medium density fiberboard) "because of different emissions characteristics and the fact that plywood presses are often manually loaded and unloaded (unlike reconstituted wood product presses that have automated loaders and unloaders)."[4] By virtue of issuing emission control standards only for reconstituted wood products presses, the USEPA essentially determined that emissions capture and control is practicable for these types of presses, but not plywood presses. In the September 2019 PCWP NESHAP risk and technology review proposal, the USEPA did not propose to add standards for plywood presses.

The USEPA Reasonably Available Control Technology/Best Available Control Technology/ Lowest Achievable Emission Rate, or simply "RBLC," database includes no entries for plywood presses with add-on emissions controls. The USEPA's database of emission sources that was developed for the risk and technology review of the PCWP NESHAP indicates that no plywood presses at HAP major sources are enclosed or controlled.

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

Plywood presses are not enclosed because they need to be accessed by employees. Plywood manufacturing facilities typically have one layup line that feeds multiple presses. On the layup line, layers of dried veneer are laid down in alternating directions with resin applied between each layer. At

---

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

[4] USEPA, "National Emission Standards for Hazardous Air Pollutants for Plywood and Composite Wood Products Manufacturing—Background Information for Final Standards." February 2004.

the end of the line, the layered mat is trimmed, stacked, and moved to the press infeed area for each press. This configuration requires more operating space and manual input than other wood products manufacturing processes. Plywood presses are batch processes and loading the press is manually assisted (the press charger is manually loaded). Operators must be able to observe press operation to check that the press is properly loaded. Pressed plywood is removed from the area, typically by using a forklift. Adding an enclosure to capture emissions is not feasible because it would disrupt operation of the press (both infeed and outfeed), inhibit maintenance activities, and create unsafe working conditions for employees (isolation, heat, and emissions).

As detailed above, there are no technically feasible control options to capture or control plywood press PM_{10} emissions. Therefore, the plywood presses were excluded from further evaluation in the PM_{10} Analysis.

2.1.4 Pneumatic Conveyors (4CON)

The Pneumatic Conveyor emissions unit represents a collection of miscellaneous conveyors, cyclones, and target boxes used to handle and transport materials around the facility. Transported materials include chips, sawdust, plytrim, and sanderdust from both off-site sources and on-site activities. Individual process units, grouped within the Pneumatic Conveyor emissions unit, include the following:

- T&G saw cyclone no. 5
- T&G saw cyclone no. 4
- Veneer saw cyclone no. 3
- Hogged fuel blow pipe
- Target box no. 2
- Target box no. 3
- Sanderdust pneumatic conveyor

Only the emission units that meet the threshold of 90 percent contribution to the total facility PM_{10} emissions rate are listed above. Each emissions unit meeting the 90 percent contribution threshold is discussed in more detail in the following subsections.

2.1.4.1 T&G Saw Cyclone no. 5

T&G saw cyclone no. 5 (process unit CY5 in the existing permit) controls PM emissions generated by use of the T&G saw and detail saw in the main production building. PM emissions (i.e., plytrim residuals) enter into T&G saw cyclone no. 5 where centrifugal forces are imparted on larger-diameter particles in the conical chamber. The centrifugal forces influence the larger-diameter particles to move toward the cyclone walls, resulting in collection of plytrim residuals at the bottom of the cone. Collected plytrim residuals are then routed to T&G saw cyclone no. 4.

Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone. Exhaust parameters for the T&G saw cyclone are summarized in Section 2.4.

2.1.4.2 T&G Saw Cyclone no. 4

T&G saw cyclone no. 4 (process unit CY4 in the existing permit) routes collected plytrim residuals from T&G saw cyclone no. 5 to the downstream Plytrim Baghouse. The operation and control mechanisms of T&G saw cyclone no. 4 are identical to the descriptions presented in Section 2.1.4.1, except that collected plytrim residuals (i.e., particle fallout from the cone) are routed to the Plytrim Baghouse.

Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone. Exhaust parameters for T&G saw cyclone no. 4 are summarized in Section 2.4.

2.1.4.3 Veneer Saw Cyclone no. 3

The Veneer saw cyclone no. 3 (process unit CY3 in the existing permit) controls PM emissions generated by use of the core saw in the veneer storage building. The operation and control mechanisms of Veneer saw cyclone no. 3 are identical to the descriptions presented in Section 2.1.4.1, except that collected plytrim residuals (i.e., particle fallout from the cone) combine with plytrim residuals from T&G saw cyclone no. 4, and are routed to the Plytrim Baghouse.

Smaller-diameter particles in the exhaust stream are emitted to atmosphere, via fluid drag forces, through an opening located on the top of the cyclone. Exhaust parameters for the Veneer saw cyclone no. 4 are summarized in Section 2.4.

2.1.4.4 Hogged Fuel Blow Pipe

The hogged fuel blow pipe (process unit BP1 in the existing permit) is a fully sealed, high-pressure blow line delivering hogged fuel across the facility. Hogged fuel is loaded into the blow pipe, using an enclosed chute with an airlock from the hog. Loaded hogged fuel is routed to either target box no. 2 or target box no. 3 (target box nos. 2 and 3 are discussed in more detail in the following subsections).

Based on communications with the facility, target box no. 3 is the actual point of emissions, and the hogged fuel blow pipe does not represent an emissions unit. Hence, the hogged fuel blow pipe is not an emissions unit and is shown incorrectly in the existing permit. Therefore, the hogged fuel blow pipe was excluded from further evaluation in the Analysis. Note that the permit error will be corrected in the next permitting cycle for the facility.

2.1.4.5 Target Box no. 2

Hogged fuel is routed primarily to target box no. 2 (process unit TB2 in the existing permit) via the hogged fuel blow pipe. Target box no. 2 is used to deliver hogged fuel into the hogged fuel silo. Based on communications with the facility, target box no. 2 is fully sealed to the top of the hogged fuel silo and does not emit. Hence, target box no. 2 is not an emissions unit and is shown incorrectly in the existing permit. Therefore, target box no. 2 was excluded from further evaluation in the Analysis. Note that the permit error will be corrected in the next permitting cycle for the facility.

2.1.4.6 Target Box no. 3

Hogged fuel is also routed to target box no. 3 (process unit TB3 in the existing permit) via the hogged fuel blow pipe. Target box no. 3 is used only to drop hogged fuel to a pile, adjacent to the hogged fuel loading area, when the silo is completely full. Exhaust parameters for target box no. 3 are presented in Section 2.4.

2.1.4.7 Sanderdust Pneumatic Conveyor

PM emissions (i.e., sanderdust) generated by the plywood sander are collected in two Torit baghouses. Collected sanderdust is loaded onto the sanderdust pneumatic conveyor (no process unit ID is presented in the existing permit) through rotary airlocks located at the bottom of each baghouse. The sanderdust pneumatic conveyor is used to route sanderdust to the downstream bin vent baghouse located atop the sanderdust truck loading bin. Collected sanderdust from the bin vent baghouse is dropped into the sanderdust truck loading bin via the attached rotary air lock. Exhaust parameters for the sanderdust pneumatic conveyor are presented in Section 2.4.

2.1.5 Materials Handling (2MT)

The Materials Handling emissions unit consists of miscellaneous equipment used to handle hogged fuel, bark, chips, sawdust, and sanderdust, including conveying these materials around the facility. Individual process units, grouped in the Materials Handling emissions unit, include the following:

- Hogged fuel pile-fuel loader
- Chip loading bin and associated pile
- Hogged fuel truck unloading ramp
- Hogged fuel and bark bins
- Plytrim truck loading bin

Only the emission units that meet the threshold 90 percent contribution to the total emissions rate for the facility are listed above. Each emission unit is described in more detail in the relevant section below.

2.1.5.1 Hogged Fuel Pile-Fuel Loader

A wheel loader, referred to in the existing permit as hogged fuel pile-fuel loader (process unit FL1), is used to transport hog fuel from the pile created by target box no. 3 and the hogged fuel truck dump area. The hogged fuel pile-fuel loader delivers stockpiled hogged fuel to the hog fuel conveyor, which feeds into the hogged fuel silo. Fugitive emissions are generated as the wheel loader transports material to the covered hogged fuel conveyor. Control of the fugitive particulate emissions generated by the wheel loader activities is considered to be technically infeasible. Therefore, the hogged fuel pile-fuel loader was excluded from further evaluation in the Analysis.

2.1.5.2 Chip Loading Bin and Associated Pile

There are three chip loading bins (process units B3, B4, and B5 in the existing permit) and a chip pile located in close proximity to the veneer production building. Two chip loading bins are fed by two open box chain conveyors, referred to in the existing permit as the chip conveyor and the bark conveyor. The third chip loading bin is fed by target box no. 1 (process unit TB1 in the existing permit). The actual point of emissions for the chip loading bins is limited to the dropping of chips into trucks (emissions generated by the chip and bark conveyors and target box no. 1 are accounted for elsewhere) and the cleanup of the associated pile.

As trucks drive under the chip loading bins, the bin door bottoms open, and green chips are loaded. The open sides of the bin doors and height of the truck sides provide adequate protection from wind, helping to limit fugitive emissions. Access material is dropped to the adjacent chip pile when trucks overload or have to make specific weight targets. This pile is periodically removed by a front-end loader, which feeds a nearby conveyor that is used to route chips to the hogged fuel bin (process unit B2 in the existing permit) as needed. It is important to note that the chips have high moisture contents resulting in minimal emissions of fine particulate.

The loading of trucks via the chip loading bins and the process of clearing the pile represent sources of fugitive particulate emissions. Control of fugitive particulate emissions generated by each emissions unit is considered to be technically infeasible, since capture and collection cannot reasonably be achieved without altering truck and/or worker access (e.g., creating safety concerns). Based on the fugitive nature of each emissions unit, the chip loading bins and associated pile emissions unit were excluded from further evaluation in the Analysis.

2.1.5.3 Hogged Fuel Truck Unloading Ramp

The hogged fuel truck unloading ramp (process unit HFR1 in the existing permit) is used for unloading hogged fuel delivered in semi-trucks from off-site sources. As the semi-trucks drive onto the unloading ramp, hogged fuel is dumped from the trucks to an adjacent hogged fuel storage pile. Enclosure and control of fugitive particulate emissions is considered to be technically infeasible since the semi-trucks dump from the unloading ramp and adequate space is required for access and unloading activities. Therefore, the hogged fuel truck unloading ramp was excluded from further evaluation in the Analysis.

2.1.5.4 Hogged Fuel and Bark Bins

The hogged fuel and bark bins (process unit B2 in the existing permit) are used to load material into outbound trucks near the veneer production building. Both bins are used only when the hogged fuel blow pipe is down for maintenance purposes. The normal operation is to route bark through the hogged fuel blow pipe to the hogged fuel silo or pile via target box nos. 2 and 3, respectively.

The hogged fuel and bark bin can also be supplied green chips by the adjacent conveyor. This conveyor receives green chips from the front-end loader used to periodically to clean up the pile identified in Section 2.1.5.2.

Similar to Section 2.1.5.2, the loading of trucks, via the hogged fuel and bark bins, represents a source of fugitive particulate emissions. Control of fugitive particulate emissions generated by use of the bins is considered to be technically infeasible, since capture and collection cannot reasonably be achieved. Based on the fugitive nature of the emissions unit and the infrequent use of the bins, the hogged fuel and bark bins emissions unit was excluded from further evaluation in the Analysis.

2.1.5.5 Plytrim Truck Loading Bin

The plytrim truck loading bin (process unit B8 in the existing permit) is used to drop plytrim residuals into outbound trucks to be hauled off site. Plytrim residuals are delivered to the bin via an airlock attached to the Plytrim Baghouse located directly on top of the plytrim truck loading bin.

Similar to the description provided in Section 2.1.5.2, the loading of trucks, via the plytrim truck loading bin, represents a source of fugitive particulate emissions. Control of fugitive particulate emissions generated by use of the bins is considered to be technically infeasible, since capture and collection cannot reasonably be achieved without altering truck and/or worker access (e.g., creating safety concerns). Therefore, the plytrim truck loading bin was excluded from further evaluation in the Analysis.

2.1.6 Paved and Unpaved Roads (6WE)

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

2.2 Sources of NO_X Emissions

A summary of the selected emission units and associated NO_X emission rates to be evaluated in the Analysis is presented in Table 2-2 (attached). As shown in the table, only the hogged fuel boiler is included as a source for further evaluation in the Analysis. See Section 2.1.1 for a description of the hogged fuel boiler emissions unit and associated existing control devices.

2.3 Sources of SO_2 Emissions

A summary of the selected emission units and associated SO_2 emission rates to be evaluated in the Analysis is presented in Table 2-3 (attached). As shown in the table, only the hogged fuel boiler is included as a source for further evaluation in the Analysis. See Section 2.1.1 for a description of the hogged fuel boiler emissions unit and associated existing control devices.

2.4 Emission Unit Exhaust Parameters

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

3 REGIONAL HAZE FOUR FACTOR ANALYSIS METHODOLOGY

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

3.1 Step 1: Determine Emission-Control Measures to Consider

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

3.2 Step 2: Selection of Emissions

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

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

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

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

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

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

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

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

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

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

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

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

4 PM_{10} ANALYSIS

The Analysis for PM_{10} emissions follows the six steps previously described in Section 0.

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

4.1.1 Baghouses

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

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

Certain process limitations can affect the operation of baghouses in some applications. For example, exhaust streams with very high temperatures (i.e., greater than 500°F) may require specially formulated filter materials and/or render baghouse control infeasible. Additional challenges include the particle characteristics, such as materials that are "sticky" and tend to impede the removal of material from the filter surface. Exhaust gases that exhibit corrosive characteristics may also impose limitations on the effectiveness of baghouses. There is also the concern for combustible wood dust creating a potential spark hazard within the baghouse (i.e., generating embers within the collector). As a result, a spark detection/extinguishment system will be necessary in certain wood product applications. In wood products applications it is expected that particle characteristics, specifically particle and exhaust moisture content, may limit the feasibility on implementation. However, for some sources, baghouses are considered technically feasible.

4.1.2 Wet Venturi Scrubbers

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

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

As wet scrubbers become saturated with a pollutant it is necessary to discharge (blowdown) some scrubber liquid and add fresh water. A water treatment system of suitable size is necessary to handle the scrubber blowdown. The Glendale facility is not connected to a city sewer system. The facility is reliant on a septic system. The amount of scrubber blowdown that would be created for an appropriately sized wet scrubber would likely overwhelm the septic system.

As a result, a wet scrubber system is considered technically infeasible for this facility location.

4.1.3 Electrostatic Precipitator

ESPs are used extensively for control of PM emissions. An ESP is a particulate control device that uses electrical force to move particles entrained with a gas stream onto collection surfaces. An electrical charge is imparted on the entrained particles as they pass through a corona, a region where gaseous ions flow. Electrodes in the center of the flow lane are maintained at high voltage and generate the corona that charges the particles, thereby allowing for their collection on the oppositely charged collector walls. Due to these electrical forces, there is high concern for combustible wood dust creating a potential spark hazard within an ESP (i.e., generating embers within the collector). As a result, a spark detection/extinguishment system will be necessary in order to mitigate the potential for deflagration events, at a minimum. Prior to an actual installation, a vendor evaluation will be necessary to determine if there are site-specific hazards that will preclude this control option due to safety concerns. Under the current timeline, a vendor inspection was not possible by an outside ESP vendor prior to submitting this Analysis.

In wet ESPs, the collectors are either intermittently or continuously washed by a spray of liquid, usually water. Instead of the collection hoppers used by dry ESPs, wet ESPs utilize a drainage system and water treatment of some sort. In dry ESPs, the collectors are knocked, or "rapped," by various mechanical means to dislodge the collected particles, which slide downward into a hopper for collection.

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

Similar to wet scrubber control systems, wet ESPs also create a water pollution concern. The effluent wastewater and wet sludge stream created by the wet ESP requires the operating facility to have an appropriately sized water treatment system and subsequent disposal system in place. The overall amount of wastewater generated by operating in the wet ESP may likely overwhelm the septic system.

As a result, while a dry ESP is considered a technically feasible control device option, a wet ESP is considered technically infeasible for this facility location.

4.2 Step 2—Selection of Emissions

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

4.3 Step 3—Characterizing Cost of Compliance

Tables 4-2 and 4-3 (attached) present the detailed cost analyses of the technically feasible PM_{10} control technologies included in the Analysis. Note the sanderdust pneumatic conveyor is already controlled by the bin vent baghouse and therefore, was not included in Table 4-2 (e.g., baghouse cost effectiveness derivation table). A summary of the cost of compliance, expressed in $/ton, is shown below in Table 4-1:

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

Emissions Unit	Process Unit ID	Cost of Compliance ($/ton)	
		BH	Dry ESP
Trim Saw Cyclone #5	CY5	$12,818	$14,459
T&G Saw Cyclone #4	CY4	$23,234	$26,214
Veneer Saw Cyclone #3	CY3	$58,414	$65,500
Target Box #3	TB3	$78,615	$94,268
Sanderdust Pneumatic Conveyor	--	--	$101,309

4.4 Step 4—Characterizing Time Necessary for Compliance

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

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

4.5.1 Energy Impacts

Energy impacts can include electricity and/or supplemental fuel used by a control device. Electricity use can be substantial for large projects if the control device uses large fans, pumps, or motors. Similarly, processes based on thermal oxidation may use significant amounts of fossil fuels, which can lead to economic impacts as well as climate change impacts.

Baghouse control systems require significant electricity use to operate the powerful fans required to overcome the pressure drop across the filter bags. Dry ESPs are expected to require even more electricity than baghouses, since high-voltage electricity is required for particle collection and removal. Dry ESPs also require powerful fans to maintain exhaust flow through the system.

4.5.2 Environmental Impacts

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

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

4.6 Step 6—Characterize Remaining Useful Life

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

5 NO_X ANALYSIS

The Analysis for NO_X emissions follows the six steps previously described in Section 0.

5.1 Step 1—Determine NO_X Control Measures for Consideration

5.1.1 Selective Non-Catalytic Reduction

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

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

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

One disadvantage of SNCR, and any control systems that rely on the ammonia and NO reaction, is that excess ammonia (commonly referred to as "ammonia slip") must be injected to ensure the highest level of control. Higher excess ammonia generally results in a higher 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%) 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%) and the lower temperatures at which the reaction can take place (400°F to 800°F, depending on the catalyst selected). SCR is widely used for combustion processes, such as those using natural gas turbines, where the type of fuel produces a relatively clean combustion gas. In an SNCR/SCR hybrid system, ammonia or urea is injected into the combustion chamber to provide the initial reaction with NO_X emissions, followed by a catalytic (SCR) section that further enhances the reduction of NO_X emissions. The primary reactions that take place in the presence of the catalyst are:

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

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

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

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

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

5.1.3 Low NOx Burner

Low NO_X burners are a viable technology for a number of fuels, including sanderdust and natural gas. Low NO_X burner technology is used to moderate and control, via a staged process, the fuel and air mixing rate in the combustion zone. This modified mixing rate reduces the oxygen available for thermal NO_X formation in critical NO_X formation zones, and/or decreases the amount of fuel burned at peak flame temperatures. These techniques are also referred to as staged combustion or sub-stoichiometric combustion to limit NO_X formation.

Combustion in hogged fuel boilers commonly occurs on grates, including the Dutch-oven-type hogged fuel boiler at the facility, and does not utilize the types of burners typically employed for low NO_X burner applications. Potential reductions in NO_X emissions from these types of boilers (without add-on controls) are limited by the boiler furnace geometry, air flow controls, and burner zone stoichiometry, making retrofitting applications difficult. The hogged fuel boiler at the facility is regularly inspected for fine-tuning and/or routine maintenance of the boiler systems. As a result, it is expected that the hogged fuel boiler is already optimized for NO_X performance.

In order to achieve effective NO_X reductions from low NO_X burners, a complete replacement of the hogged fuel boiler system, including fans, air control systems, firebox, and steam generating tubes, would likely be required. The Federal Guidance Document identifies several criteria for selecting control measures in the Analysis, including emission reductions through improved work practices, retrofits for sources with no existing controls, and upgrades or replacements for existing, less effective controls. None of these criteria identify or recommend whole replacement of emission units. Based on the challenges with retrofitting the hogged fuel boiler and the Federal Guidance Document criteria, low NO_X burners for hogged fuel boilers were excluded from further consideration in the Analysis.

5.2 Step 2—Selection of Emissions

See Sections 2.2 for descriptions of the NO_X emission units and emission rates selected for the Analysis.

5.3 Step 3—Characterizing Cost of Compliance

Table 5-1 presents the detailed cost analysis of the only technically feasible NO_X control technology (e.g., SNCR) included in the Analysis. The cost estimate is based on a heated urea-based injection system, instead of aqueous ammonia injection, because of storage safety concerns. The cost of compliance for the SNCR installation on the hogged fuel boiler is $12,265 per ton of NO_X emissions controlled.

5.4 Step 4—Characterizing Time Necessary for Compliance

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

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

5.5.1 Energy Impacts

Direct energy impacts will result from the use of SNCR control systems. Energy use (e.g. electricity use) is limited to the operation of pumps for urea injection into the SNCR and the heating of the urea storage tank. As a result, direct energy impacts are expected to be minimal. SNCR systems also consume fossil fuels, primarily natural gas, during the ammonia production process, and in order to mitigate the increased moisture loads caused by the urea injection in the flue gas.

5.5.2 Environmental Impacts

SNCR units require the use of urea (or aqueous ammonia) injection in the exhaust stream. Any unreacted excess ammonia in the exhaust stream (i.e., ammonia slip) will be released to the atmosphere. Ammonia slip to the atmosphere is a contributor to fine particle formation, which further exacerbates the regional haze issue; ammonia is also considered to be a toxic air contaminant with associated human health risks, and is regulated under the Cleaner Air Oregon Program. Hence, there is a trade-off between maximizing NO_X emission reductions and minimizing the potential for ammonia slip.

5.6 Step 6—Characterize Remaining Useful Life

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

6 SO_2 ANALYSIS

The Analysis for SO_2 emissions follows the six steps previously described in Section 0.

6.1 Step 1—Determine SO_2 Control Measures for Consideration

6.1.1 Dry Sorbent Injection

SO_2 scrubbers are control devices typically used on stationary utility and industrial boilers, especially those combusting high sulfur fuels such as coal or oil. SO_2 scrubbers are not common for wood-fired boiler applications because of the inherent low sulfur content of the fuel.

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

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

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

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

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

6.2 Step 2—Selection of Emissions

See Sections 2.3 for a description of the SO_2 emission units and emission rates selected in the Analysis.

6.3 Step 3—Characterizing Cost of Compliance

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

6.4 Step 4—Characterizing Time Necessary for Compliance

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

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

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

6.6 Step 6—Characterize Remaining Useful Life

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

7 CONCLUSION

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

LIMITATIONS

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

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

TABLES

Table 2-1
PM_{10} Evaluation for Regional Haze Four Factor Analysis
Swanson Group Mfg. LLC—Glendale, Oregon

Emission Unit(s) (1)	Emission Unit ID (1)	Current PM_{10} Control Technology (1)	Annual PM_{10} Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Technology Evaluation	Control Technologies to be Evaluated
Trim Saws Cyclone #5 (CY5)	4CON	–	25.8	Yes	–	Baghouse, Wet Venturi Scrubber Electrostatic Precipitator
Hogged Fuel Boiler	1PH	Multiclone & Dry ESP	19.3	No	Source is directly regulated for filterable PM as a surrogate for metal under Area Source Boiler GACT, which became effective after July 31, 2013. Therefore, this source meets EPA guidance for no further analysis.	–
Hog Fuel Pile-Fuel Loader (FL1)	2MT	–	19.1	No	Fugitive source.	–
Chip Loading Bin (B3, B4, and B5) and Pile	2MT	–	17.4	No	Fugitive source.	–
Plywood Presses	P1, P2, P3	–	16.0	No	Accessibility and design limitations make control technically infeasible.	–
T&G Saw Cyclone #4 (CY4)	4CON	–	14.2	Yes	–	Baghouse, Wet Venturi Scrubber Electrostatic Precipitator
Hog Fuel Truck Unloading Ramp (HFR1)	2MT	–	11.7	No	Fugitive source.	–
Paved Roads	6WE	Sweeping & Watering	10.3	No	Fugitive source.	–
Veneer Dryers Fugitives	5VDa	–	9.9	No	Fugitive source and recent reconstruction to minimize fugitives.	–
Hog Fuel and Bark Bins (B2)	2MT	–	7.5	No	Fugitive source and minimal use.	–
Plytrim Truck Loading Bin (B8)	2MT	–	6.0	No	Fugitive source.	–
Veneer Saw Cyclone #3 (CY3)	4CON	–	6.0	Yes	–	Baghouse, Wet Venturi Scrubber Electrostatic Precipitator
Hog Fuel Blow Pipe (BP1)	4CON	–	4.9	No	Not an emissions unit (to be corrected with next permitting cycle).	–
Target Box #2 (TB2)	4CON	–	3.4	No	Not an emissions unit (to be corrected with next permitting cycle).	–
Target Box #3 (TB3)	4CON	–	3.4	Yes	–	Baghouse, Wet Venturi Scrubber Electrostatic Precipitator
Sanderdust Pneumatic Conveyer	4CON	Baghouse	3.1	Yes	–	Wet Venturi Scrubber, Electrostatic Precipitator
All other sources (includes conveyors, veneer dryer RTO, target boxes, truck loading bins, glue mixers, aggregate insignificant)	Varies	Varies by emission unit	22.0	No	This collection of emission units falls below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	–

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

MAUL FOSTER ALONGI

Table 2-2
NO_x Evaluation for Regional Haze Four Factor Analysis
Swanson Group Mfg. LLC—Glendale, Oregon

Emission Unit (1)	Emission Unit ID (1)	Current NO_x Control Technology (1)	Annual NO_x Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Technology Evaluation	Control Technologies to be Evaluated
Hogged Fuel Boiler	1PH	–	71.2	Yes	–	Selective Catalytic Reduction, Selective Non-Catalytic Reduction, Low-NOx Burners
Veneer Dryers	5VD	–	0.4	No	This emission unit falls below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	–

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

Table 2-3
SO_2 Evaluation for Regional Haze Four Factor Analysis
Swanson Group Mfg. LLC—Glendale, Oregon

Emission Unit (1)	Emission Unit ID (1)	Current SO_2 Control Technology (1)	Annual SO_2 Emissions (2) (tons/yr)	Control Evaluation Proposed?	Rationale for Exclusion from Control Technology Evaluation	Control Technologies to be Evaluated
Hogged Fuel Boiler	1PH	–	3.9	Yes	–	Dry Sorbent Injection
Veneer Dryers	5VD	–	0.04	No	This emission unit falls below the 90th percentile threshold. Only the top 90th percentile of emission units contributing to the total facility emission rate will be evaluated.	–

REFERENCES:

(1) Information taken from the Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

(2) Information taken from the Review Report for Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

MAUL FOSTER ALONGI

Table 2-4
Emissions Unit Input Assumptions and Exhaust Parameters
Swanson Group Mfg. LLC—Glendale, Oregon

Emissions Unit ID (1)	Emissions Unit Description (1)	Process Unit ID	Control Evaluation Proposed? (Yes/No)			Heat Input Capacity (MMBtu/hr)	Exhaust Parameters		
			PM_{10} (2)	NO_X (3)	SO_2 (4)		Exit Temperature (°F)	Exit Flowrate (acfm)	Exit Flowrate (scfm)
1PH	Hogged Fuel Boiler	ESP	No	Yes	Yes	125 (1)	417 (5)	69,633 (5)	31,743 (5)
4CON	Trim Saws Cyclone #5	CY5	Yes	No	No	–	70 (6)	11,500 (7)	10,927 (a)
4CON	T&G Saw Cyclone #4	CY4	Yes	No	No	–	70 (6)	11,500 (7)	10,927 (a)
4CON	Veneer Saw Cyclone #3	CY3	Yes	No	No	–	70 (6)	15,000 (7)	14,253 (a)
4CON	Target Box #3	TB3	Yes	No	No	–	70 (6)	2,300 (7)	2,185 (a)
4CON	Sanderdust Pneumatic Conveyer	–	Yes	No	No	–	70 (6)	1,200 (7)	1,140 (a)

NOTES:

acfm = actual cubic feet per minute.

ESP = electrostatic precipitator.

ft/sec = feet per second.

MMBtu/hr = million British thermal units per hour.

scfm = standard cubic feet per minute.

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

Facility elevation above sea level (ft) = 1,437 (8)

REFERENCES:

(1) Information taken from the Review Report for Title V Operating Permit no. 10-0045-TV-01 issued June 12, 2017 by the Oregon DEQ.

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

(3) See Table 2-2, NO_X Evaluation for Regional Haze Four Factor Analysis.

(4) See Table 2-3, SO_2 Evaluation for Regional Haze Four Factor Analysis. Each SO_2 control technology is considered to be technically infeasible.

(5) See source test report, Table 3 "Hog Fuel Boiler," prepared by Bighorn Environmental Air Quality dated April 1, 2014.

(6) The process exhaust is at ambient conditions. Assumes 70°F as representative.

(7) Information provided by Swanson Group Mfg. LLC.

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

Table 3-1
Utility and Labor Rates
Swanson Group Mfg. LLC—Glendale, Oregon

Parameter	Value	(units)	
FACILITY OPERATIONS			
Annual Hours of Operation	8,760	(hrs/yr)	(1)
Annual Days of Operation	365	(day/yr)	(1)
Daily Hours of Operation	24	(hrs/day)	(1)
UTILITY COSTS			
Electricity Rate	0.079	($/kWh)	(2)
Natural Gas Rate	2.69	($/MMBtu)	(3)
Water Rate	4.58	($/Mgal)	(a)
Wood Fuel Rate	25.0	($/BDT)	(3)
Landfill Disposal Rate	60.0	($/ton)	(3)
Compressed Air Rate	0.0039	($/Mscf)	(b)
LABOR COSTS			
Maintenance Labor Rate	36.48	($/hr)	(3)
Operating Labor Rate	24.26	($/hr)	(3)
Supervisory Labor Rate	27.99	($/hr)	(3)
Operating Labor Hours per Shift	2	(hrs/shift)	(7)
Maintenance Labor Hours per Shift	1	(hrs/shift)	(7)
Typical Shifts per Day	3	(shifts/day)	(8)

NOTES:

BDT = bone dry ton.

Mgal = thousand gallons.

MMBtu = million British thermal units.

Mscf = thousand standard cubic feet.

MWh = megawatt-hour.

(a) Water cost ($-2019/Mgal) = (water cost [$-2018/Mscf]) / (2018 CEPCI annual index) x (2019 CEPCI annual index)

Water cost ($-2018/gal) =	4.55	(4)
1998 CEPCI annual index =	389.5	(5)
2019 CEPCI annual index =	607.5	(5)

(b) Compressed air cost ($-2019/Mscf) = (compressed air cost [$-1998/Mscf]) / (1998 annual CEPCI index) x (2019 annual CEPCI index)

Compressed air cost ($-1998/Mscf) =	0.0025	(6)
1998 annual CEPCI index =	389.5	(5)
2019 annual CEPCI index =	607.5	(5)

REFERENCES:

(1) Assumes continuous annual operation.

(2) Information provided by Swanson Group Mfg. LLC. Assumes industrial average rate for Pacific Power.

(3) Information provided by Swanson Group Mfg. LLC.

(4) Water and sewer costs obtained from "50 Largest Cities Water & Wastewater Rate Survey" prepared Black & Veatch Management Consulting, LLC dated 2018-2019. See exhibit B, Figure 19. Note this reference was provided in the USEPA Air Pollution Control Cost Manual, Section 3, Chapter 1 "Carbon Adsorbers" calculation spreadsheet.

(5) See Chemical Engineering magazine, CEPCI section for annual indices.

(6) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. Cost presented in section 1.5.1.8 assumed to be representative.

(7) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See table 1.5.1.1 and 1.5.1.3. Conservatively assumes the minimum labor requirement of range presented.

(8) USEPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See table 1.11. Assumes operator shifts per day as representative.

Table 4-2
Cost Effectiveness Derivation for Baghouse Installation
Swanson Group Mfg. LLC—Glendale, Oregon

Process Unit ID	Emissions Unit Description	Input Parameters: Exhaust Flowrate [1] (acfm)	Input Parameters: PM_{10} Annual Emissions Estimate [2] (tons/yr)	Pollutant Removed by Control Device [a] (tons/yr)	Operating Parameter: Electrical Requirements [4] (kW)	Operating Parameter: Number of Filter Bags Required [4]
CY5	Trim Saws Cyclone #5	11,500	25.8	25.6	60.4	152
CY4	T&G Saw Cyclone #4	11,500	14.2	14.1	60.4	152
CY3	Veneer Saw Cyclone #3	15,000	6.0	5.91	73.1	196
TB3	Target Box #3	2,300	3.4	3.39	25.2	34

Process Unit ID	Emissions Unit Description	Direct Costs: Purchased Equipment Cost: Basic Equip./Services Cost [4]	Direct Costs: Purchased Equipment Cost: Total [b]	Direct Costs: Total Direct Cost [c]	Total Indirect Costs [d]	Total Capital Investment [e]	Capital Recovery Cost (CRC): Control Device (CRC) [f]	Capital Recovery Cost (CRC): Replacement Parts: Filter Bag Cost [4]	Capital Recovery Cost (CRC): Replacement Parts: Bag Labor Cost [h]	Capital Recovery Cost (CRC): Replacement Parts: Filter Bag (CRC) [i]
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC_D	C_B	C_L	CFC_B
CY5	Trim Saws Cyclone #5	$105,990	$125,068	$232,618	$56,281	**$288,899**	$22,693	$2,293	$1,386	$1,083
CY4	T&G Saw Cyclone #4	$105,990	$125,068	$232,618	$56,281	**$288,899**	$22,693	$2,293	$1,386	$1,083
CY3	Veneer Saw Cyclone #3	$113,861	$134,355	$248,778	$60,460	**$309,238**	$24,291	$2,948	$1,788	$1,394
TB3	Target Box #3	$53,971	$63,686	$125,814	$28,659	**$154,473**	$12,134	$506	$310	$240

Process Unit ID	Direct Annual Costs: Operating Labor: Operator Cost [j]	Direct Annual Costs: Operating Labor: Supervisor Cost [k]	Direct Annual Costs: Maintenance: Labor Cost [j]	Direct Annual Costs: Maintenance: Material Cost [14]	Direct Annual Costs: Utilities: Electricity Cost [l]	Direct Annual Costs: Utilities: Compressed Air Cost [m]	Direct Annual Costs: Landfill Cost [n]	Direct Annual Costs: Total Direct Annual Costs [14]	Total Indirect Annual Costs [o]	Total Annual Cost [p]	Annual Cost Effectiveness [q]
USEPA COST MANUAL VARIABLE	--	--	--	--	--	--	--	DAC	IAC	TAC	($/ton)
CY5	$53,129	$7,969	$39,946	$39,946	$41,747	$23,569	$1,534	$208,923	$118,843	**$327,766**	**$12,818**
CY4	$53,129	$7,969	$39,946	$39,946	$41,747	$23,569	$845	$208,234	$118,843	**$327,077**	**$23,234**
CY3	$53,129	$7,969	$39,946	$39,946	$50,509	$30,742	$355	$223,989	$121,254	**$345,244**	**$58,414**
TB3	$53,129	$7,969	$39,946	$39,946	$17,421	$4,714	$203	$163,568	$102,907	**$266,475**	**$78,615**

See notes and formulas on following page.

Table 4-2 (Continued)
Cost Effectiveness Derivation for Baghouse Installation
Swanson Group Mfg. LLC—Glendale, Oregon

NOTES:

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

Baghouse control efficiency (%) = 99.0 (3)

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

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

Site preparation cost, SP ($) = 15,000 (6)
Building cost, Bldg. ($) = 0 (7)

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

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

(f) Capital recovery cost of control device ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (8)

Control device capital recovery factor = 0.0786 (g)

(g) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs}] - 1); see reference (9).

Interest rate (%) = 4.75 (10)
Baghouse economic life (yr) = 20 (11)
Filter bag economic life (yr) = 4 (12)

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

Total time required to change one bag (min/bag) = 15 (13)
Maintenance labor rate ($/hr) = 36.48 (14)

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

Filter bag capital recovery factor = 0.2804 (g)

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

Operating labor hours per shift [hrs/shift) = 2 (14)
Maintenance labor hours per shift [hrs/shift) = 1 (14)
Shifts per day (shifts/day) = 3 (14)
Annual days of operation (days/yr) = 365 (14)
Operator labor rate ($/hr) = 24.26 (14)
Maintenance labor rate ($/hr) = 36.48 (14)

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

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

Electricity rate ($/kWh) = 0.079 (14)
Annual hours of operation (hrs/yr) = 8,760 (14)

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

Compressed air rate ($/Mscf) = 0.0039 (14)
Annual hours of operation (hrs/yr) = 8,760 (14)

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

Landfill disposal rate ($/ton) = 60.0 (14)

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

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

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

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 2-1, PM_{10} Evaluation for Regional Haze Four Factor Analysis.
(3) US EPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-025) for baghouse (fabric filter), pulse-jet cleaned type issued July 15, 2003. Assumes minimum typical new equipment design efficiency.
(4) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. In the quote, costs and equipment requirements for three differently sized baghouses (5,000 cfm, 20,000 cfm, and 50,000 cfm) are presented. For the smallest exhaust flowrate above (MC4), these quoted data was scaled using a ratio. All other costs/data were scaled and obtained using trendline formulas. It is important to note that the quoted costs do not include the costs associated with taxes, installation of equipment, all concrete work (including excavation, engineering, plumbing, electrical construction), building/foundation upgrades, and permitting or licensing. The cost for an add-on spark detection/extinguishment system is included due to concerns about combustible wood dust.
(5) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See Table 1.9 "Capital Cost Factors for Fabric Filters." The 1.18 factor includes instrumentation, sales tax, and freight.
(6) Information provided by Swanson Group Mfg. LLC. The site preparation cost only accounts for concrete foundation work (approximately $600 per cubic yard and an estimated pad size of 15-ft by 15-ft by 1-ft deep) ,and obtaining a professional engineer stamp. The pad size estimate does not represent an engineering design value and requires further analysis.
(7) Conservatively assumes no costs associated with site preparation or building requirements.
(8) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(9) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(10) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(11) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.2.
(12) Western Pneumatics, Inc. Quotation #P30733DJB dated January 28, 2020. Typical bag filter life is 4 years.
(13) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.1.4.
(14) See Table 3-1, Utility and Labor Rates.
(15) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 "Baghouse and Filters" issued December 1998. See section 1.5.

Table 4-3
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Swanson Group Mfg. LLC—Glendale, Oregon

Process Unit ID	Emissions Unit Description	Input Parameters: Exhaust Flowrate [1] (acfm)	Input Parameters: Exhaust Flowrate [1] (scfm)	Input Parameters: PM_{10} Annual Emissions Estimate [2] (tons/yr)	Pollutant Removed by Control Device [a] (tons/yr)	Operating Parameter: System Pressure Drop [4] (inch w.c.)	Operating Parameter: Total Collection Plate Area Estimate [b] (ft^2)	Operating Parameter: ESP Inlet Grain Loading [c] (gr/ft^3)
CY5	Trim Saws Cyclone #5	11,500	10,927	25.8	25.6	6.00	4,371	0.060
CY4	T&G Saw Cyclone #4	11,500	10,927	14.2	14.1	6.00	4,371	0.033
CY3	Veneer Saw Cyclone #3	15,000	14,253	6.0	5.91	6.00	5,701	0.011
TB3	Target Box #3	2,300	2,185	3.4	3.39	6.00	874	0.040
–	Sanderdust Pneumatic Conveyer	1,200	1,140	3.1	3.096	6.00	456	0.069

Process Unit ID	Emissions Unit Description	Direct Costs: Purchased Equipment Cost: Basic Equip./Services Cost [9]	Direct Costs: Purchased Equipment Cost: Total [d]	Direct Costs: Total Direct Cost [e]	Total Indirect Costs [f]	Total Capital Investment [g]	Capital Recovery Cost of Control Device [h]
USEPA COST MANUAL VARIABLE		A	B	DC	IC	TCI	CRC_D
CY5	Trim Saws Cyclone #5	$573,294	$676,487	$1,157,511	$385,597	$1,543,108	$121,212
CY4	T&G Saw Cyclone #4	$573,294	$676,487	$1,157,511	$385,597	$1,543,108	$121,212
CY3	Veneer Saw Cyclone #3	$594,367	$701,353	$1,199,037	$399,771	$1,598,809	$125,587
TB3	Target Box #3	$517,902	$611,124	$1,048,355	$348,341	$1,396,695	$109,711
–	Sanderdust Pneumatic Conveyer	$511,279	$603,309	$1,035,303	$343,886	$1,379,189	$108,336

Process Unit ID	Direct Annual Costs: Operating Labor: Operator Cost [j]	Operating Labor: Supervisor Cost [k]	Operating Labor: Coordinator Cost [l]	Maintenance: Labor Cost [m]	Maintenance: Material Cost [n]	Utilities: Fan Electricity Cost [o]	Utilities: Oper. Electricity Cost [p]	Utilities: Compressed Air Cost [q]	Utilities: Landfill Cost [r]	Total Direct Annual Costs [14]	Total Indirect Annual Costs [s]	Total Annual Cost [t]	Annual Cost Effectiveness [u]
USEPA COST MANUAL VARIABLE	--	--	--	--	--	--	--	--	--	DAC	IAC	TAC	($/ton)
CY5	$53,129	$7,969	$17,710	$6,416	$6,765	$8,632	$5,861	$23,569	$1,551	$131,602	$238,130	$369,731	$14,459
CY4	$53,129	$7,969	$17,710	$6,416	$6,765	$8,632	$5,861	$23,569	$854	$130,904	$238,130	$369,034	$26,214
CY3	$53,129	$7,969	$17,710	$6,416	$7,014	$11,259	$7,644	$30,742	$359	$142,241	$244,882	$387,123	$65,500
TB3	$53,129	$7,969	$17,710	$6,416	$6,111	$1,726	$1,172	$4,714	$206	$99,153	$220,380	$319,533	$94,268
–	$53,129	$7,969	$17,710	$6,416	$6,033	$901	$612	$2,459	$188	$95,417	$218,258	$313,675	$101,309

See notes and formulas on following page.

Table 4-3 (Continued)
Cost Effectiveness Derivation for Dry Electrostatic Precipitator (ESP) Installation
Swanson Group Mfg. LLC—Glendale, Oregon

NOTES:

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

Control efficiency (%) =	99.0	(3)

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

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

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

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

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

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

Site preparation cost, SP ($) =	27,778	(8)
Building cost, Bldg. ($) =	0	(9)

(f) Total indirect cost ($) = (0.57) x (total purchased equipment cost [$]); see reference (7).

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

(h) Capital recovery cost of control device($) = (total capital investment [$]) x (control device capital recovery factor); see reference (10).

Control device capital recovery factor =	0.0786	(i)

(i) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate (%) / 100]^[economic life {yrs}]) / ([1 + (interest rate |%| / 100)]^[economic life {yrs}] - 1); see reference (11).

Interest rate (%) =	4.75	(12)
Dry ESP economic life (yr) =	20	(13)

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

Operator labor rate ($/hr) =	24.26	(6)
Operating labor hours per shift (hrs/shift) =	2	(6)
Shifts per day (shifts/day) =	3	(6)
Annual days of operation (days/yr) =	365	(6)

(k) Supervisor labor cost ($) = (0.15) x (operating labor cost [$]); see reference (14).

(l) Coordinator labor cost ($) = (1/3) x (operator labor cost [$]); see reference (14).

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

Maintenance labor cost ($-1999)	4,125	(14)
1999 annual chemical engineering plant cost index =	390.6	(15)
2019 annual chemical engineering plant cost index =	607.5	(15)

(n) Maintenance material cost ($) = (0.01) x (total purchased equipment cost [$]); see reference (14).

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

Annual hours of operation (hrs/yr) =	8,760	(6)
Electricity rate ($/kWh) =	0.079	(6)

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

Annual hours of operation (hrs/yr) =	8,760	(6)
Electricity rate ($/kWh) =	0.079	(6)

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

Compressed air rate ($/Mscf) =	0.0039	(6)
Annual hours of operation (hrs/yr) =	8,760	(6)

(r) Annual landfill cost ($) = (4.29E-06) x (ESP inlet grain loading [gr/ft^3]) x (annual hours of operation [hrs/yr]) x (exhaust flowrate [acfm]) x (landfill disposal rate [$/ton]); see reference (14).

Annual hours of operation (hrs/yr) =	8,760	(6)
Landfill disposal rate ($/ton) =	60.0	(6)

(s) Total indirect annual cost ($) = (0.60) x ([operator labor cost {$}] + [supervisor labor cost {$}] + [maintenance labor cost {$}] + [maintenance material cost {$}]) + (0.04) x (total capital investment [$]) + (capital recovery cost [$]); see reference (14).

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

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

REFERENCES:

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

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

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

(4) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 3 "Electrostatic Precipitators" issued September 1999. See section 3.2.3. Assumes the average system (including ductwork and collection system) pressure drop of range provided.

(5) PPC Industries Quotation no. 18048/18049 (Revision 0) dated September 12 and 13, 2018. MFA obtained two separate costs and equipment requirements for dry ESPs sized at 21,000 acfm and 51,000 acfm. For the smallest exhaust flowrate above (MC4), the quoted data was scaled using a ratio. All other costs/data were scaled and obtained using trendline formulas. It is important to note that the quoted costs do not include the costs associated with taxes, freight, mechanical construction, electrical work, excavation, building/foundation upgrades, and permitting or licensing. The cost for an add-on spark detection/extinguishment system is included due to concerns about combustible wood dust.

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

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

(8) Information provided by Swanson Group Mfg. LLC. The site preparation cost only accounts for concrete foundation work (approximately $600 per cubic yard and an estimated pad size of 20-ft by 20-ft by 2-ft deep) ,and obtaining a professional engineer stamp. The pad size estimate does not represent an engineering design value and requires further analysis.

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

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

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

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

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

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

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

Table 5-1
Cost Effectiveness Derivation for Selective Non-Catalytic Reducer Installation
Swanson Group Mfg. LLC—Glendale, Oregon

Emissions Unit ID	Emissions Unit Description	Input Parameters: Heat Input Capacity (1) (MMBtu/hr)	Input Parameters: Uncontrolled NO_X Emissions Estimate: Hourly (a) (lb/hr)	Input Parameters: Uncontrolled NO_X Emissions Estimate: Annual (3) (tons/yr)	Input Parameters: Uncontrolled NO_X Emissions in Flue Gas (b) (lb/MMBtu)	Pollutant Removed by Control Device: Hourly (c) (lb/hr)	Pollutant Removed by Control Device: Annual (d) (tons/yr)	Normalized Stoichiometric Ratio (e)	Operating Parameters: Reagent Mass Consumption (f) (lb/hr)	Operating Parameters: Reagent Solution Flowrate (g) (gal/hr)	Operating Parameters: Power Demand (h) (kW)	Operating Parameters: Water Demand (i) (gal/hr)	Operating Parameters: Additional Fuel Usage (j) (MMBtu/hr)
USEPA COST MANUAL VARIABLE		Q_B	--	--	$NO_{X_{in}}$	--	--	NSR	$m_{reagent}$	q_{sol}	P	q_{water}	ΔFuel
1PH	Hogged Fuel Boiler	125	16.3	71.2	0.13	4.06	17.8	1.85	19.6	4.13	36.4	18.8	0.16

Emissions Unit ID	Emissions Unit Description	Direct Cost: Capital Cost (k)	Indirect Cost: Balance of Plant Cost (l)	Total Capital Investment (m)	Capital Recovery Cost of Control Device (n)	Direct Annual Costs: Maintenance Labor and Material Cost (p)	Direct Annual Costs: Reagent Usage (q)	Direct Annual Costs: Utilities: Electricity Cost (s)	Direct Annual Costs: Utilities: Water Usage Cost (t)	Direct Annual Costs: Utilities: Fuel Additive Cost (u)	Direct Annual Costs: Utilities: Ash Disposal Cost (v)	Direct Annual Costs: Total Direct Annual Costs (27)	Total Indirect Annual Costs (w)	Total Annual Cost (x)	Annual Cost Effectiveness (y)
USEPA COST MANUAL VARIABLE		$SNCR_{cost}$	BOP_{cost}	TCI	CR	--	--	--	--	--	--	DAC	IDAC	TAC	($/ton)
1PH	Hogged Fuel Boiler	$330,501	$579,996	$1,308,522	$102,785	$19,628	$67,290	$25,165	$754	$1,987	$83.46	$114,907	$103,374	$218,281	$12,265

NOTES:

(a) Uncontrolled hourly NO_X emissions estimate (lb/hr) = (uncontrolled annual NO_X emissions estimate [tons/yr]) x (2,000 lb/ton) / (annual hours of operation [hrs/yr])
Annual hours of operation (hrs/yr) = 8,760 (2)

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

(c) Hourly pollutant removed by control device (lb/hr) = (uncontrolled hourly NO_X emissions estimate [lb/hr]) x (control efficiency [%] / 100)
Control efficiency (%) = 25.0 (4)

(d) Annual pollutant removed by control device (tons/yr) = (uncontrolled annual NO_X emissions estimate [tons/yr]) x (control efficiency [%] / 100)
Control efficiency (%) = 25.0 (4)

(e) Normalized stoichiometric ratio = ([2] x [uncontrolled NOX emissions in flue gas (lb/MMBtu)] + [0.7]) x (control efficiency [%] / 100) / (uncontrolled NOX emissions in flue gas [lb/MMBtu]); see reference (5).
Control efficiency (%) = 25.0 (4)

(f) Reagent mass consumption (lb/hr) = (uncontrolled NOX emissions in flue gas [lb/MMBtu]) x (heat input capacity [MMBtu/hr]) x (normalized stoichiometric ratio) x (60.06 lb-urea/lb-mole) / (46.01 lb-NO_2/lb-mole) / (theoretical stoichiometric ratio]); see reference (6).
Theoretical stoichiometric ratio = 2 (7)

(g) Reagent solution flowrate (gal/hr) = (reagent mass consumption [lb/hr]) / (aqueous reagent solution concentration [%] / 100) / (aqueous reagent solution density [lb/ft³]) x (7.4805 gal/ft³); see reference (8).
Aqueous reagent solution concentration (%) = 50.0 (8)
Aqueous reagent solution density (lb/ft³) = 71.0 (8)

(h) Power demand (kW) = (0.47) x (uncontrolled NOX emissions in flue gas [lb/MMBtu]) x (normalized stoichiometric ratio) x (heat input capacity [MMBtu/hr]) / (net plant heat rate [MMBtu/MWh]) + (power required to heat tank [kW]); see reference (9).
Net plant heat rate (MMBtu/MWh) = 10.0 (10)
Power required to heat tank (kW) = 35.0 (11)

(i) Water demand (gal/hr) = (4) x (reagent mass consumption [lb/hr]) / (aqueous reagent solution concentration [%] / 100) / (density of water [lb/gal]); see reference (12).
Aqueous reagent solution concentration (%) = 50.0 (8)
Density of water (lb/gal) = 8.345

(j) Additional fuel usage (MMBtu/hr) = (9) x (heat of vaporization of water [Btu/lb]) x (reagent mass consumption [lb/hr]) x (MMBtu/1,000,000 Btu); see reference (13).
Heat of vaporization of water (Btu/lb) = 900 (13)

(k) Capital cost ($) = (capital cost [1999 $/MMBtu/hr]) x (heat input capacity [MMBtu/hr]) x (chemical engineering plant cost index for 2019) / (chemical engineering plant cost index for 1999)
Capital cost (1999 $/MMBtu/hr) = 1,700 (4)
Chemical engineering plant cost index for 2019 = 607.5 (14)
Chemical engineering plant cost index for 1999 = 390.6 (14)

(l) Balance of plant costs ($) = (213,000) x ([heat input capacity (MMBtu/hr)] / [net plant heat rate (MMBtu/MWh)])^(0.33) x (hourly pollutant removed by control device [lb/hr])^(0.12) x (retrofit factor); see reference (15).
Net plant heat rate (MMBtu/MWh) = 10.0 (10)
Retrofit factor = 1.00 (15)

(m) Total capital investment ($) = (1.3) x ([capital cost ($)] + [balance of plant cost ($)]) + (reagent storage tank cost [$]) + (reagent storage tank construction [$]); see reference (16).
Reagent storage tank ($) = 74,875 (17)
Reagent storage area construction ($) = 50,000 (18)

(n) Capital recovery cost of control device ($) = (total capital investment [$]) x (control device capital recovery factor); see reference (19).
Control device capital recovery factor = 0.0786 (o)

(o) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate (%) / 100]^[economic life (yrs)]) / ([1 + (interest rate [%] / 100)]^[economic life (yrs)] - 1); see reference (20).
Interest rate (%) = 4.75 (21)
SNCR economic life (yr) = 20 (22)

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

(q) Annual reagent usage cost ($) = (reagent solution flowrate [gal/hr]) x (reagent cost [$/50% urea solution]) x (annual hours of operation [hrs/yr])
Reagent rate ($/50% urea solution) = 1.86 (r)
Annual hours of operation (hrs/yr) = 8,760 (2)

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

(s) Annual electricity cost ($) = (power demand [kWh]) x (electricity rate [$/kWh]) x (annual hours of operation [hrs/yr])
Electricity rate ($/kWh) = 0.079 (2)
Annual hours of operation (hrs/yr) = 8,760 (2)

(t) Annual water usage cost ($) = (water demand [gal/hr]) x (Mgal/1,000 gal) x (water rate [$/Mgal]) x (annual hours of operation [hrs/yr])
Water rate ($/Mgal) = 4.58 (2)
Annual hours of operation (hrs/yr) = 8,760 (2)

(u) Annual fuel additive cost ($) = (additional fuel usage [MMBtu/hr]) x (annual hours of operation [hrs/yr]) x (wood fuel rate ($/BDT) / (high heat value of wood [MMBtu/BDT]; see reference (24).
High heat value of wood (MMBtu/BDT) = 17.48 (25)
Wood fuel rate ($/BDT) = 25.0 (2)
Annual hours of operation (hrs/yr) = 8,760 (2)

(v) Ash disposal ($) = (additional fuel usage [MMBtu/hr]) x (ash weight percent [%] / 100) x (annual hours of operation [hrs/yr]) / (high heat value of wood [MMBtu/BDT]) x (landfill disposal rate [$/ton]); see reference (26).
Ash weight percent (%) = 1.75 (27)
Annual hours of operation (hrs/yr) = 8,760 (2)
High heat value of wood (MMBtu/BDT) = 17.48 (25)
Landfill disposal rate ($/ton) = 60.0 (2)

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

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

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

REFERENCES:

(1) See Table 2-4, Emissions Unit Input Assumptions and Exhaust Parameters.
(2) See Table 3-1, Utility and Labor Rates.
(3) See Table 2-2, NO_X Evaluation for Regional Haze Four Factor Analysis.
(4) USEPA Air Pollution Control Technology Fact Sheet (EPA-452/F-03-031) for selective non-catalytic reduction (SNCR) issued July 15, 2003. Assumes the average PM control efficiency and average capital cost.
(5) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.17.
(6) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.18.
(7) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. Assumes theoretical stoichiometric ratio for urea.
(8) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equations 1.19 and 1.20.
(9) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.42.
(10) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.3.1.
(11) Information provided by Chromalox vendor. Assumes heating of urea is required to a minimum of 95°F.
(12) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.45.
(13) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.48.
(14) See Chemical Engineering magazine, Chemical Engineering Plant Cost Index (CEPCI) for annual indices.
(15) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.37. Assumes retrofit factor.
(16) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.35.
(17) Cost representative of 12,500 gallon double-wall, heated, storage tank provided by National Tank Outlet and Chromalox. Cost includes freight charges, but excludes sales tax.
(18) Assumes engineering estimate cost of construction for a covered storage tank (e.g., including engineering design services, concrete/foundation/secondary containment area work, and structure construction).
(19) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.
(20) USEPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.
(21) See the Regional Haze: Four Factor Analysis fact sheet prepared by the Oregon DEQ. Assumes the EPA recommended bank prime rate of 4.75% as a default.
(22) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See section 1.4.2.
(23) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.39.
(24) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.49.
(25) 40 CFR, Subchapter C, Part 98, Subpart C. See Table C-1 "Default CO2 Emission Factors and High Heat Values of Various Types of Fuel". Factor for wood and wood residuals.
(26) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equations 1.50 and 1.51.
(27) Assumes typical average ash weight percent from the burning of hogged fuel.
(28) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.38.
(29) USEPA Air Pollution Control Cost Manual, Section 4, Chapter 1 "Selective Non-Catalytic Reduction" issued April 25, 2019. See equation 1.52 and 1.53.